HELIX ENERGY SOLUTIONS GROUP INC
Form 10-K
February 21, 2014

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

R	ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
	For the fiscal year ended December 31, 2013
	OR
£	TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
	For the transition period from to

Commission File Number 001-32936

HELIX ENERGY SOLUTIONS GROUP, INC.
(Exact name of registrant as specified in its charter)

Minnesota (State or other jurisdiction of incorporation or organization)	95-3409686 (I.R.S. Employer Identification No.)
3505 West Sam Houston Parkway North Suite 400 Houston, Texas (Address of principal executive offices)	77043 (Zip Code)

(281) 618-0400
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock (no par value)	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:
None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. R Yes £ No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. £ Yes R No

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. R Yes £ No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). R Yes £ No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. £

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer R	Accelerated filer £	Non-accelerated filer £ (Do not check if a smaller reporting company)	Smaller reporting company £

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). £ Yes R No

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant based on the last reported sales price of the Registrant's Common Stock on June 30, 2013 was approximately $2.3 billion.

The number of shares of the registrant's Common Stock outstanding as of February 18, 2014 was 105,733,623.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive Proxy Statement for the Annual Meeting of Shareholders to be held on May 1, 2014, are incorporated by reference into Part III hereof.

HELIX ENERGY SOLUTIONS GROUP, INC. INDEX — FORM 10-K

Table of Contents

Forward Looking Statements

This Annual Report on Form 10-K ("Annual Report") contains various statements that contain forward-looking information regarding Helix Energy Solutions Group, Inc. and represent our expectations and beliefs concerning future events. This forward looking information is intended to be covered by the safe harbor for "forward-looking statements" provided by the Private Securities Litigation Reform Act of 1995 as set forth in Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). All statements included herein or incorporated herein by reference that are predictive in nature, that depend upon or refer to future events or conditions, or that use terms and phrases such as "achieve," "anticipate," "believe," "estimate," "expect," "forecast," "plan," "project," "propose," "strategy," "predict," "envision," "hope," "intend," "will," "cont "potential," "should," "could" and similar terms and phrases are forward-looking statements. Included in forward-looking statements are, among other things:

- statements regarding our business strategy or any other business plans, forecasts or objectives, any or all of which is subject to change;
- statements relating to the construction, upgrades or acquisition of vessels or equipment and any anticipated costs related thereto, including the construction of the Q5000 and the Q7000 and our recent commitment to enter the Brazil market using two newly-constructed chartered vessels which are expected to be delivered in 2016. For more information regarding our vessel construction activity, see Item 1. Business "— Our Operations";
- statements regarding projections of revenues, gross margin, expenses, earnings or losses, working capital or other financial items;
- statements regarding any financing transactions or arrangements, or ability to enter into such transactions;
- statements regarding anticipated legislative, governmental, regulatory, administrative or other public body actions, requirements, permits or decisions;
- statements regarding the collectability of our trade receivables;
- statements regarding anticipated developments, industry trends, performance or industry ranking;
- statements regarding general economic or political conditions, whether international, national or in the regional and local market areas in which we do business;
- statements related to our ability to retain key members of our senior management and key employees;
- statements related to the underlying assumptions related to any projection or forward-looking statement; and
- any other statements that relate to non-historical or future information.

Although we believe that the expectations reflected in these forward-looking statements are reasonable and are based on reasonable assumptions, they do involve risks, uncertainties and other factors that could cause actual results to be materially different from those in the forward-looking statements. These factors include, among other things:

- impact of domestic and global economic conditions and the future impact of such conditions on the oil and gas industry and the demand for our services;
- unexpected delays in the delivery or chartering of new vessels for our well intervention and robotics fleet, including the Q5000 (expected in 2015), the Q7000 (expected in 2016), the Grand Canyon II (expected in late 2014) and the Grand Canyon III (expected in 2015);
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unexpected delays in the delivery of the chartered vessels required to perform recently contracted work in Brazil, which could result in delay payments as well as loss of revenues under terms of the contracts;

- unexpected future capital expenditures (including the amount and nature thereof);
- the effectiveness and timing of completion of our vessel upgrades and major maintenance items;
- the results of our continuing efforts to control costs and improve performance;
- the success of our risk management activities;
- the effects of competition;
- the effects of indebtedness, which could adversely restrict our ability to operate, could make us vulnerable to general adverse economic and industry conditions, could place us at a competitive disadvantage compared to our competitors that have less debt and could have other adverse consequences to us;
- the impact of current and future laws and governmental regulations, including tax and accounting developments;

Table of Contents

- the effect of adverse weather conditions and/or other risks associated with marine operations;
- the effectiveness of our current and future hedging activities;
- the long-term availability (or lack thereof) of capital (including any financing) to fund our business strategy and/or operations, and the terms of any such financing;
- the potential impact of a loss of one or more key employees; and
- the impact of general, market, industry or business conditions.

Our actual results could differ materially from those anticipated in any forward-looking statements as a result of a variety of factors, including those discussed in “Risk Factors” beginning on page 16 of this Annual Report. All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by these risk factors. Forward-looking statements are only as of the date they are made, and other than as required under the securities laws, we assume no obligation to update or revise these forward-looking statements or provide reasons why actual results may differ.

PART I

Item 1. Business

OVERVIEW

Helix Energy Solutions Group, Inc. (together with its subsidiaries, unless context requires otherwise, “Helix”, the “Company”, “we,” “us” or “our”) is an international offshore energy company that provides specialty services to the offshore energy industry, with a focus on well intervention and robotics operations. We seek to provide services and methodologies that we believe are critical to developing offshore reservoirs and maximizing production economics. Our “life of field” services are segregated into four disciplines: well intervention, robotics, subsea construction and production facilities. We primarily conduct operations in the Gulf of Mexico, North Sea, Asia Pacific and West Africa regions. For additional information regarding our strategy and business operations, see sections titled “Our Strategy” and “Our Operations” included elsewhere within Item 1. Business of this Annual Report.

Our principal executive offices are located at 3505 West Sam Houston Parkway North, Suite 400, Houston, Texas 77043; our phone number is 281-618-0400. Our common stock trades on the New York Stock Exchange (“NYSE”) under the ticker symbol “HLX.” Our Chief Executive Officer submitted the annual CEO certification to the NYSE as required under its Listed Company Manual in June 2013. Our principal executive officer and our principal financial officer have made the certifications required under Section 302 of the Sarbanes-Oxley Act, which are included as exhibits to this Annual Report.

Please refer to the subsection “— Certain Definitions” on page 14 for definitions of additional terms commonly used in this Annual Report. Unless otherwise indicated any reference to Notes herein refers to Notes to Consolidated Financial Statements in Item 8. Financial Statements and Supplementary Data located elsewhere in this Annual Report.

BACKGROUND

Helix was incorporated in the state of Minnesota in 1979. Until June 2009, Helix owned the majority of the common stock of a separate publicly-traded entity, Cal Dive International, Inc. (NYSE: DVR, and collectively with its subsidiaries referred to as “Cal Dive”), which performed shelf contracting services. Helix sold substantially all of its ownership interests in Cal Dive during 2009 and its then remaining ownership interest in 2011. In February 2013, we sold Energy Resource Technology GOM, Inc. (“ERT”), a former wholly-owned U.S. subsidiary that conducted our oil and gas operations in the Gulf of Mexico (see “Discontinued Operations” below). In mid-2013, we sold our two remaining subsea construction pipelay vessels and related equipment and in January 2014, we sold our related spoolbase facilities located in Ingleside, Texas (see “Our Operations” below).

OUR STRATEGY

Over the past few years, we have improved our balance sheet and increased our liquidity through dispositions of non-core business assets as well as reductions in the amount of our debt outstanding. With the completion of the sales of ERT and our pipelay vessels and related assets, we are now positioned to expand and grow our remaining operations.

Table of Contents

Our focus is to expand our well intervention and robotics businesses. We believe that focusing on these businesses will deliver higher long-term financial returns to us than the businesses and assets that we have monetized. We are making strategic investments that expand our service capabilities or add capacity to existing services in our key operating regions. The Helix 534, which underwent upgrades and modifications to render it suitable for use as a well intervention vessel, commenced well intervention operations in February 2014. Our well intervention fleet will expand following the completion of the two newbuild semisubmersible vessels currently under construction, the Q5000 and the Q7000, which are expected to be delivered in 2015 and 2016, respectively. Additionally, we have announced that we will charter two newbuild monohull vessels for use in connection with agreements that we have entered into with Petróleo Brasileiro S.A. (“Petrobras”). The monohull vessels are scheduled for delivery to us in 2016. During 2013, we chartered and then subsequently fully equipped and integrated the Skandi Constructor into our North Sea well intervention operations. In addition, we are expanding our robotics operations by acquiring additional remotely operated vehicles (“ROVs”) and trenchers as well as chartering two newbuild ROV support vessels, the Grand Canyon II and the Grand Canyon III, which are expected to be delivered in 2014 and 2015, respectively. We also chartered the Rem Installer, which was delivered to us in July 2013.

OUR OPERATIONS

Historically, our well intervention, robotics, subsea construction and production facilities operations were reported as two segments: Contracting Services and Production Facilities. Following the completion of the sale of our two remaining subsea construction pipelay vessels and the continued emphasis on growing our well intervention and robotics businesses, we disaggregated our former Contracting Services segment into three reportable segments: Well Intervention, Robotics and Subsea Construction. We provide a full range of services primarily in deepwater in the Gulf of Mexico, North Sea, Asia Pacific and West Africa regions. Our Subsea Construction activities are now significantly diminished following the sale of substantially all of our existing assets related to this reportable segment. Production Facilities remains a business segment and consists of our majority ownership of a dynamically positioned floating production vessel, the Helix Producer I (the “HP I”), our equity investments in Deepwater Gateway, L.L.C. (“Deepwater Gateway”) and Independence Hub, LLC (“Independence Hub”), and the Helix Fast Response System (the “HFRS”). All of our production facilities activities are located in the Gulf of Mexico. We have recently reached agreement with our minority partner to acquire its noncontrolling interests in the entity that owns the HP I (Note 4). See Note 14 for financial results associated with our continuing business segments. Previously, we had an additional business segment, Oil and Gas, which was sold in February 2013 (see “Discontinued Operations” below). Our current services include:

- Production. Inspection, repair and maintenance of production structures, trees, jumpers, risers, pipelines and subsea equipment; well intervention; life of field support; and intervention engineering.

- Reclamation. Reclamation and remediation services; plugging and abandonment services; pipeline abandonment services; and site inspections.

- Development. Installation of subsea pipelines, flowlines, control umbilicals, manifold assemblies and risers; burial of pipelines; installation and tie-in of riser and manifold assembly; commissioning, testing and inspection; and cable and umbilical lay and connection. We have experienced increased demand for our services from the alternative energy industry. Some of the services we provide to these alternative energy businesses include subsea power cable installation, trenching and burial, along with seabed coring and preparation for construction of wind turbine foundations.

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Production facilities. We are able to provide oil and natural gas processing services to oil and natural gas companies, primarily those operating in the deepwater of the Gulf of Mexico using our HP I vessel. Currently, the HP I is being utilized to process production from the Phoenix field (Note 3). In addition to the services provided by our HP I vessel, we maintain equity investments in two production hub facilities in the Gulf of Mexico.

- Fast Response System. We established the HFRS as a response resource that can be identified in permit applications to federal and state agencies.

Table of Contents

Demand for our services is primarily influenced by the oil and gas industry, and in particular, the willingness of oil and gas companies to make capital expenditures for offshore exploration, drilling and production operations. The performance of our business is also largely dependent on prevailing market prices for oil and natural gas, which are impacted by global economic conditions, hydrocarbon production and capacity, geopolitical issues, weather, and several other factors, including but not limited to:

- worldwide economic activity, including available access to global capital and capital markets;
- demand for oil and natural gas, especially in the United States, Europe, China and India;
- economic and political conditions in the Middle East and other oil-producing regions;
- the effect of regulations on offshore Gulf of Mexico oil and gas operations;
- actions taken by the Organization of the Petroleum Exporting Countries ("OPEC");
- the availability and discovery rate of new oil and natural gas reserves in offshore areas;
- the exploration and production of shale oil and natural gas;
- the cost of offshore exploration for and production and transportation of oil and gas;
- the ability of oil and natural gas companies to generate funds or otherwise obtain external capital for exploration, development and production operations;
- the sale and expiration dates of offshore leases in the United States and overseas;
- technological advances affecting energy exploration production transportation and consumption;
- weather conditions;
- environmental and other governmental regulations; and
- domestic and international tax policies.

We believe that the long-term industry fundamentals are positive based on the following factors: (1) long-term increasing world demand for oil and natural gas emphasizing the need for continual replenishment of oil and gas production; (2) mature global production rates for offshore and subsea wells; (3) globalization of the natural gas market; (4) increasing number of mature and small reservoirs; (5) increasing offshore activity, particularly in deepwater; and (6) increasing number of subsea developments.

Well Intervention

We engineer, manage and conduct well construction, intervention and asset retirement operations in water depths ranging from 200 to 10,000 feet. The increased number of subsea wells installed, the efficiency gains from specialized intervention assets and the periodic shortfall in both rig availability and equipment have resulted in an increased demand for well intervention services.

As major and independent oil and gas companies expand operations in the deepwater basins of the world, development of these reserves will often require the installation of subsea trees. Historically, drilling rigs were typically necessary for subsea well intervention to troubleshoot or enhance production, shift sleeves, log wells or perform recompletions. Our vessels serve as work platforms for well intervention services at costs that are typically significantly less than offshore drilling rigs. Competitive advantages of our vessels are derived from their lower operating costs, together with an ability to mobilize quickly and to maximize operational time by performing a broad range of tasks related to intervention, construction, inspection, repair and maintenance. These services provide a cost advantage in the development and management of subsea reservoirs. We expect long-term demand for these services to increase due to the growing number of subsea tree installations. As of December 31, 2013, our well intervention backlog was approximately $1.6 billion, including $593.8 million expected to be performed in 2014.

In the Gulf of Mexico, our multi-service semi-submersible vessel, the Q4000, has set a series of well intervention "firsts" in increasingly deeper water without the use of a traditional drilling rig. In 2010, the Q4000 served as a significant component in the Macondo well control and containment efforts. The Q4000 also serves an important role in the HFRS that was established in 2011. In August 2012, we acquired the Discoverer 534 drillship from a subsidiary of Transocean Ltd. The vessel, renamed the Helix 534, underwent upgrades and modifications to render it suitable for use as a well intervention vessel and commenced well intervention operations in February 2014. Our total investment for the Helix 534 was approximately $218 million.

In March 2012, we executed a contract with a shipyard in Singapore for the construction of a newbuild semisubmersible well intervention vessel, the Q5000. This $386.5 million shipyard contract represents the majority of the expected costs associated with the construction of the Q5000. Pursuant to the

Table of Contents

terms of this contract, payments are made in a fixed percentage of the contract price, together with any variations, on contractually scheduled dates. At December 31, 2013, our total investment in the Q5000 was $210.6 million, including $173.8 million of scheduled payments made to the shipyard. We plan to spend approximately $146 million on the Q5000 in 2014, including scheduled shipyard payments of $115.9 million. The vessel is expected to be completed and placed in service in 2015.

In September 2013, we executed a second contract with the same shipyard in Singapore that is currently constructing the Q5000. This contract provides for the construction of a newbuild semi-submersible well intervention vessel, the Q7000, which will be built to North Sea standards. This $346.0 million shipyard contract represents the majority of the expected costs associated with the construction of the Q7000. Pursuant to the terms of this contract, 20% of the contract price was paid upon the signing of the contract and the remaining 80% will be paid upon the delivery of the vessel. At December 31, 2013, our total investment in the Q7000 was $76.7 million, including the $69.2 million paid to the shipyard upon signing the contract.

In the North Sea, the Seawell has provided well intervention and abandonment services for hundreds of North Sea subsea wells since 1987. In December 2014, the vessel is scheduled for major maintenance and upgrades, which will extend the life of the vessel. The Well Enhancer has performed well intervention, abandonment and coil tubing services since it joined our fleet in the North Sea region in 2009. In April 2013, we chartered the Skandi Constructor for use in our North Sea operations. The vessel was subsequently configured to perform well intervention operations and it commenced service in that capacity in September 2013. The initial term of the charter will expire in March 2016.

In February 2014, we entered into agreements with Petrobras to provide well intervention services offshore Brazil. The initial term of the agreements with Petrobras is for four years with options to extend. In connection with the Petrobras agreements, we entered into charter agreements with Siem Offshore AS for two newbuild monohull vessels, both of which are expected to be in service for Petrobras in 2016. Our total investment in the topside equipment for both vessels is expected to be approximately $260 million.

Robotics

We have been actively engaged in robotics for over 25 years. We operate ROVs, trenchers and ROVDrills designed for offshore construction, maintenance and well intervention services. As global marine construction support moves to deeper waters, the use of ROV systems has increased and the scope of ROV services is becoming even more significant. Our chartered vessels add value by supporting deployment of our ROVs. We provide our customers with vessel availability and schedule flexibility to meet the technological challenges of their subsea activities worldwide. Our robotics assets include 51 ROVs, four trenching systems and two ROVDrills. Our robotics business unit primarily operates in the Gulf of Mexico, North Sea, Asia Pacific and West Africa regions. We currently charter vessels to support our robotics operations and we have historically engaged additional vessels on short-term (spot) charter agreements as needed.

In July 2013, the Rem Installer, a newbuild ROV support vessel, was delivered to us under terms of a charter that will expire in July 2016. In February 2013, we entered into charter agreements for the Grand Canyon II and the Grand Canyon III, which are expected to be delivered in 2014 and 2015, respectively.

Over the past few years there has been a dramatic increase in offshore activity associated with the growing alternative (renewable) energy industry. Specifically there has been a large increase in services performed for the wind turbine industry. As the level of activity for offshore alternative energy projects has increased, so has the need for reliable services and related equipment. Historically, this work was performed with the use of barges and other similar vessels but these types of services are now being contracted to vessels such as our Deep Cygnus and Grand Canyon chartered vessels that are suitable for harsh weather conditions which can occur offshore, especially in northern Europe where offshore wind farming is currently concentrated. In 2013, revenues derived from alternative energy contracts accounted for 9% of our global robotics revenues. Looking ahead to 2014, we believe that our robotics business unit is positioned to continue the services it provides to a range of clients in the alternative energy business. This is expected to include the use of our chartered vessels, ROVs and trenchers to provide burial services relating to subsea power cables on key European wind farm developments.

Table of Contents

Subsea Construction

Previously, our subsea construction services included the use of umbilical lay and pipelay vessels and ROVs to develop fields in the deepwater. We have significantly reduced our subsea construction activities as we focus on our well intervention and robotics operations. In October 2012, we entered into an agreement to sell our two remaining pipelay vessels, the Caesar and the Express, and other related pipelay equipment for a total sales price of $238.3 million. In June 2013, we completed the sale of the Caesar and related equipment for $138.3 million and in July 2013, we completed the sale of the Express for $100 million (Note 2). In June 2013, we entered into an agreement to sell our spoolbase property located in Ingleside, Texas for $45 million to the same group of companies that acquired the Caesar and the Express (Note 2). The sale of Ingleside spoolbase closed in January 2014.

Production Facilities

We own interests in two production facilities in hub locations where there is potential for subsea tieback activity. There are a significant number of small discoveries that cannot justify the economics of a dedicated host facility. These discoveries are typically developed as subsea tie backs to existing facilities when capacity through the facility is available. We have invested in two over-sized facilities that allow the operators of these fields to tie back without burdening the operator of the hub reservoir. Ownership of production facilities enables us to earn a transmission company type return through tariff charges. We own a 50% interest in Deepwater Gateway, which owns the Marco Polo TLP located in 4,300 feet of water in the Gulf of Mexico. We also own a 20% interest in Independence Hub which owns the Independence Hub platform, a 105-foot deep draft, semi-submersible platform located in a water depth of 8,000 feet that serves as a regional hub for up to one billion cubic feet (“Bcf”) of natural gas production per day from multiple ultra-deepwater fields in the eastern Gulf of Mexico.

We also own the HP I, a ship-shaped dynamically positioning floating production unit capable of processing up to 45,000 barrels of oil and 80 million cubic feet (“MMcf”) of natural gas per day. The HP I is currently being used to process production from the Phoenix field. Our existing contract for service to the Phoenix field will not expire until at least December 31, 2016.

We developed the HFRS as a culmination of our experience as a responder in the Macondo well control and containment efforts. The HFRS centers on two vessels, the HP I and the Q4000, both of which played a key role in the Macondo well control and containment efforts and are currently operating in the Gulf of Mexico. In 2011, we signed an agreement with Clean Gulf Associates ("CGA"), a non-profit industry group, allowing, in exchange for a retainer fee, the HFRS to be named as a response resource in permit applications to federal and state agencies and making the HFRS available to certain CGA participants who executed utilization agreements with us. In addition, we entered into separate utilization agreements with CGA members that specified the day rates to be charged should the HFRS be deployed in connection with a well control incident. The original set of agreements expired on March 31, 2013, and we entered into a new set of substantially similar agreements with the operators who formed HWCG LLC, a Delaware limited liability company comprised of some of the original CGA members as well as other industry participants to perform the same functions as CGA with respect to the HFRS. These agreements became effective April 1, 2013, and are for a four-year term.

DISCONTINUED OPERATIONS

Our former Oil and Gas segment was engaged in prospect generation, exploration, development and production activities. We exited our oil and gas business in February 2013 upon the sale of ERT for $624 million plus additional consideration in the form of overriding royalty interests in ERT’s Wang well and certain exploration prospects. See Notes 1 and 3 for additional information regarding the sale of ERT and its results of operations prior to the sale.

8

GEOGRAPHIC AREAS

Revenue by individually significant region is as follows (in thousands):

	Year Ended December 31,		
	2013	2012	2011
United States	$345,525	$281,308	$316,869
United Kingdom	403,816	345,074	275,499
Other	127,220	219,727	109,632
Total	$876,561	$846,109	$702,000

We include the property and equipment, net of accumulated depreciation, in the geographic region in which it legally resides. The following table provides our property and equipment, net of accumulated depreciation, by individually significant region (in thousands):

	Year Ended December 31,		
	2013	2012	2011
United States	$1,195,824	$1,180,586	$1,163,320
United Kingdom	332,394	304,062	281,430
Other	76	1,227	14,919
Total	$1,528,294	$1,485,875	$1,459,669

CUSTOMERS

Our customers include major and independent oil and gas producers and suppliers, pipeline transmission companies, alternative (renewable) energy companies and offshore engineering and construction firms. The level of services required by any particular customer depends, in part, on the size of that customer's capital expenditure budget in a particular year. Consequently, customers that account for a significant portion of revenues in one fiscal year may represent an immaterial portion of revenues in subsequent fiscal years. The percent of consolidated revenue from major customers, those whose total represented 10% or more of our consolidated revenues is as follows: 2013 — Shell (14%), 2012 — Shell (12%) and 2011 — Shell (10%). We provided services to over 65 customers in 2013.

Our services projects were historically of short duration and generally were awarded shortly before mobilization. However, since 2007, we have entered into many longer term contracts. As of December 31, 2013, our consolidated backlog which is supported by written agreements or contracts totaled $2.0 billion, of which $846.0 million is expected to be performed in 2014. At December 31, 2012, our backlog totaled $829.6 million. The substantial majority of our backlog is associated with our Well Intervention and Production Facilities business segments. Backlog contracts are cancellable without penalty in many cases. Backlog is not necessarily a reliable indicator of total annual revenue for our services as contracts may be added, cancelled and in many cases modified while in progress.

COMPETITION

The oilfield services industry is highly competitive. While price is a factor, the ability to acquire specialized vessels, attract and retain skilled personnel, and demonstrate a good safety record is also important. Our principal competitors include Oceaneering International, Inc., Saipem S.p.A., Fugro N.V., DOF ASA, Aker Solutions ASA, Island Offshore and Edison Chouest Offshore Companies. Our competitors in the well intervention business also include international drilling contractors. Many of our competitors may have significantly more financial, personnel, technological and other resources available to them.

Table of Contents

TRAINING, SAFETY AND QUALITY ASSURANCE

We have established a corporate culture in which QHSE is of equal priority to our other business objectives. Our corporate goal, based on the belief that all accidents can be prevented, is to provide an incident-free workplace by focusing on risk management and safe behavior. Everyone at Helix has the authority and the duty to "STOP WORK" which they believe is unsafe. Our QHSE management systems and training programs were developed by management personnel based on common industry work practices and by employees with on-site experience who understand the risk and physical challenges of the ocean work site. As a result, management believes that our QHSE programs are among the best in the industry. We maintain a company-wide effort to reduce risks, manage change effectively, enhance and provide continuous improvements to the behavior of our people, as well as our training programs, that continue to focus on safety through open communication. The process includes the assessment of risk through the use of selected risk analysis tools, control of work through management system procedures, job risk assessment of all routine and non-routine tasks, documentation of all daily observations, collection of data and data treatment to provide the mechanism of understanding both safe and at-risk behaviors at the worksite. In addition, we schedule hazard hunts by project management on each vessel, and regularly audit QHSE management systems, both are completed with assigned responsibilities and action due dates. Contracting Services Business Units have been independently certified compliant in ISO 9001 (Quality Management Systems) and ISO 14001 (Environmental Management System).

GOVERNMENT REGULATION

Many aspects of the offshore marine construction industry are subject to extensive governmental regulations. We are subject to the jurisdiction of the U.S. Coast Guard (the "Coast Guard"), the U.S. Environmental Protection Agency (the "EPA"), three divisions of the U.S. Department of the Interior, the Bureau of Ocean Energy Management (the "BOEM"), the Bureau of Safety and Environmental Enforcement (the "BSEE") and the Office of Natural Resource Revenue (the "ONRR") and the U.S. Customs Service, as well as private industry organizations such as the American Bureau of Shipping (the "ABS"). In the North Sea, international regulations govern working hours and a specified working environment, as well as standards for diving procedures, equipment and diver health. These North Sea standards are some of the most stringent worldwide. In the absence of any specific regulation, our North Sea operations adhere to standards set by the International Marine Contractors Association and the International Maritime Organization. In addition, we operate in other foreign jurisdictions that have various types of governmental laws and regulations to which we are subject.

The Coast Guard sets safety standards and is authorized to investigate vessel and diving accidents and to recommend improved safety standards. The Coast Guard also is authorized to inspect vessels at will. We are required by various governmental and quasi-governmental agencies to obtain various permits, licenses and certificates with respect to our operations. We believe that we have obtained or can obtain all permits, licenses and certificates necessary for the conduct of our business.

The development and operation of oil and gas properties located on the Outer Continental Shelf ("OCS") of the United States is regulated primarily by the BOEM and BSEE. Among other requirements, the BOEM requires lessees of OCS properties to post bonds or provide other adequate financial assurance in connection with the plugging and abandonment of wells located offshore and the removal of all production facilities. As a service company, we are not subject to these regulations, but do depend on the demand for our services from the oil and gas industry, and therefore, our business is affected by laws and regulations, as well as changing tax laws and policies, relating to the oil and gas industry in general.

In April 2010, the Deepwater Horizon drilling rig experienced an explosion and fire, and later sank into the Gulf of Mexico. The complete destruction of the Deepwater Horizon rig also resulted in a significant release of crude oil into the Gulf. As a result of this explosion and oil spill, a moratorium was placed on offshore deepwater drilling in the United States, which was subsequently lifted in October 2010 and replaced with enhanced safety standards for offshore deepwater drilling. Operators whose deepwater operations were suspended as a result of the moratorium and who wish to resume deepwater drilling, as well as all operators initiating new deepwater drilling projects, must demonstrate compliance with these enhanced standards. The applicable standards now include Notice to Lessees (NTL), NTL 2010-N06 (Environmental NTL), NTL 2010-N10 (Compliance and Evaluation NTL), and the Final Drilling Safety Rule. Inspections will be conducted of each deepwater drilling operation for compliance with BOEM and BSEE regulations, including but not limited to the testing of blowout preventers, before drilling resumes. Deepwater operators

Table of Contents

also need to comply with the Safety and Environmental Management System ("SEMS") Rule within the deadlines specified by the regulation. Each operator must demonstrate that it has enforceable obligations that ensure that containment resources are available promptly in the event of a deepwater blowout, regardless of the company or operator involved. During 2011, the Department of the Interior established a mechanism relating to the availability of blowout containment resources, including our HFRS system, and the BOEM and BSSE are now regulating these resources. It is also expected that the BOEM and BSEE will issue further regulations regarding deepwater offshore drilling.

Additional proposals and proceedings before various federal and state regulatory agencies and the courts could affect the oil and gas industry. We cannot predict when or whether any such proposals may become effective.

ENVIRONMENTAL REGULATION

Our operations are subject to a variety of national (including federal, state and local) and international laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Numerous governmental departments issue rules and regulations to implement and enforce such laws that are often complex and costly to comply with and that carry substantial administrative, civil and possibly criminal penalties for failure to comply. Under these laws and regulations, we may be liable for remediation or removal costs, damages and other costs associated with releases of hazardous materials (including oil) into the environment, and such liability may be imposed on us even if the acts that resulted in the releases were in compliance with all applicable laws at the time such acts were performed. Some of the environmental laws and regulations that are applicable to our business operations are discussed in the following paragraphs, but the discussion does not cover all environmental laws and regulations that govern our operations.

The Oil Pollution Act of 1990, as amended ("OPA"), imposes a variety of requirements on "Responsible Parties" related to the prevention of oil spills and liability for damages resulting from such spills in waters of the United States. A "Responsible Party" includes the owner or operator of an onshore facility, a vessel or a pipeline, and the lessee or permittee of the area in which an offshore facility is located. OPA imposes liability on each Responsible Party for oil spill removal costs and for other public and private damages from oil spills. Failure to comply with OPA may result in the assessment of civil and criminal penalties. OPA establishes liability limits of $854,400 or $1,000 per gross ton for vessels other than tank vessels. Liability limits are higher for other types of facilities and could apply if our operations resulted in Responsible Party status for a spill from such a facility. The liability limits are not applicable, however, if the spill is caused by gross negligence or willful misconduct; if the spill results from violation of a federal safety, construction, or operating regulation; or if a party fails to report a spill or fails to cooperate fully in the cleanup. Few defenses exist to the liability imposed under OPA. Management is currently unaware of any oil spills for which we have been designated as a Responsible Party under OPA that will have a material adverse impact on us or our operations.

In addition, OPA requires owners and operators of vessels over 300 gross tons to provide the Coast Guard with evidence of financial responsibility to cover the cost of cleaning up oil spills from such vessels. We currently own and operate seven vessels over 300 gross tons. We have provided satisfactory evidence of financial responsibility to the Coast Guard for all of our vessels.

The Clean Water Act imposes strict controls on the discharge of pollutants into the navigable waters of the United States and imposes potential liability for the costs of remediating releases of petroleum and other substances. The controls and restrictions imposed under the Clean Water Act have become more stringent over time, and it is possible that additional restrictions will be imposed in the future. Permits must be obtained to discharge pollutants into state and federal waters. Certain state regulations and the general permits issued under the Federal National Pollutant Discharge Elimination System Program prohibit the discharge of produced waters and sand, drilling fluids, drill cuttings and certain other substances related to the exploration for, and production of, oil and gas into certain coastal and offshore waters. The Clean Water Act provides for civil, criminal and administrative penalties for any unauthorized discharge of oil and other hazardous substances and imposes liability on responsible parties for the costs of cleaning up any environmental contamination caused by the release of a hazardous substance and for natural resource damages resulting from the release. Many states have laws that are analogous to the Clean Water Act and also require remediation of releases of petroleum and other hazardous substances in state waters. Our vessels routinely transport diesel fuel to offshore rigs and platforms and also carry diesel fuel for their own use. Our vessels transport bulk chemical materials used in drilling activities and also transport liquid mud which contains oil and oil by-products. Offshore facilities and vessels operated by us have facility and vessel response plans to deal with potential spills. We believe that our operations comply in all material respects with the requirements of the Clean Water Act and state statutes enacted to control water pollution.

OCSLA provides the federal government with broad discretion in regulating the production of offshore resources of oil and gas, including authority to impose safety and environmental protection requirements applicable to lessees and permittees operating in the OCS. Specific design and operational standards may apply to OCS vessels, rigs, platforms, vehicles and structures. Violations of lease conditions or regulations issued pursuant to OCSLA can result in substantial civil and criminal penalties, as well as potential court injunctions curtailing operations and cancellation of leases. Because our operations rely on offshore oil and gas exploration and production, if the government were to exercise its authority under OCSLA to restrict the availability of offshore oil and gas leases, such action could have a material adverse effect on our financial condition and results of operations. Equally important, since August 2012, the BSSE has implemented policy guidelines (IPD No. 12-07) under which the agency will issue incidents of noncompliance directly to contractors for serious violations of BSEE regulations. As of this date, we believe we are not the subject of any civil or criminal enforcement actions under OCSLA.

The Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA") contains provisions requiring the remediation of releases of hazardous substances into the environment and imposes liability, without regard to fault or the legality of the original conduct, on certain classes of persons including owners and operators of contaminated sites where the release occurred and those companies who transport, dispose of, or arrange for disposal of hazardous substances released at the sites. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. Third parties may also file claims for personal injury and property damage allegedly caused by the release of hazardous substances. Although we handle hazardous substances in the ordinary course of business, we are not aware of any hazardous substance contamination for which we may be liable.

We operate in foreign jurisdictions that have various types of governmental laws and regulations relating to the discharge of oil or hazardous substances and the protection of the environment. Pursuant to these laws and regulations, we could be held liable for remediation of some types of pollution, including the release of oil, hazardous substances and debris from production, refining or industrial facilities, as well as other assets we own or operate or which are owned or operated by either our customers or our subcontractors.

A variety of regulatory developments, proposals or requirements and legislative initiatives have been introduced in the domestic and international regions in which we operate that are focused on restricting the emissions of carbon dioxide, methane and other greenhouse gases. For example, the U.S. Congress has from time to time considered legislation to reduce greenhouse gas emissions, and almost one-half of the states already have taken legal measures to reduce greenhouse gas emissions, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs.

In 2007, the U.S. Supreme Court held in Massachusetts, et al. v. EPA that greenhouse gases are an "air pollutant" under the Federal Clean Air Act and thus subject to future regulation. In December 2009, the EPA issued an "endangerment and cause or contribute finding" for greenhouse gases under the Federal Clean Air Act, which allowed the EPA to proceed with the adoption and implementation of regulations that would restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act. Since 2009, the EPA has issued regulations that, among other things, require a reduction in emissions of greenhouse gases from motor vehicles and that impose greenhouse gas emission limitations in Clean Air Act permits for certain stationary sources. The EPA has received petitions to regulate greenhouse gas emissions from marine vessels, but we are currently unaware of any rulemaking projects initiated pursuant to the petitions.

Additionally, in October 2009, the EPA published a final rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas sources in the United States on an annual basis, beginning in 2011 for emissions occurring in 2010. In November 2010, the EPA expanded its greenhouse reporting rule to include onshore petroleum and natural gas production, offshore petroleum and natural gas production, onshore natural gas processing, natural gas transmission, underground natural gas storage, liquefied natural gas storage, liquefied natural gas import and export, and natural gas distribution facilities. Under these rules, reporting of greenhouse gas emissions from such facilities is required on an annual basis.

We believe that we are in compliance in all material respects with the applicable environmental laws and regulations to which we are subject. We do not anticipate that compliance with existing environmental laws and regulations will have a material effect upon our capital expenditures, earnings or competitive position. However, changes in the environmental laws and regulations, or claims for damages to persons, property, natural resources or the environment, could result in substantial costs and liabilities, and thus there can be no assurance that we will not incur significant environmental compliance costs in the future.

INSURANCE MATTERS

The well intervention and robotics operations constituting majority of our services involve a high degree of operational risk. Hazards, such as vessels sinking, grounding, colliding and sustaining damage from severe weather conditions, are inherent in marine operations. These hazards can cause personal injury or loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage and the suspension of operations. Damages arising from such occurrences may result in lawsuits asserting large claims. Insurance may not be sufficient or effective under all circumstances or against all hazards to which we may be subject. A successful claim for which we are not fully insured could have a material adverse effect on our financial condition, results of operations and cash flows.

As discussed above, we maintain insurance policies to cover some of our risk of loss associated with our operations. We maintain the amount of insurance we believe is prudent based on our estimated loss potential. However, not all of our business activities can be insured at the levels we desire because of either limited market availability or unfavorable economics (limited coverage for the underlying cost).

Our energy and marine insurance is renewed annually on July 1 and covers a twelve-month period from July 1 to June 30.

We maintain Hull and Increased Value insurance, which provides coverage for physical damage up to an agreed amount for each vessel. The deductibles are $1.0 million on the Q4000, the HP I and the Well Enhancer, and $500,000 on the Seawell and the Helix 534. In addition to the primary deductibles, the vessels are subject to an annual aggregate deductible of $5 million. We also carry Protection and Indemnity ("P&I") insurance which covers liabilities arising from the operation of the vessels and General Liability insurance which covers liabilities arising from construction operations. The deductible on both the P&I and General Liability is $100,000 per occurrence. Onshore employees are covered by Workers' Compensation. Offshore employees and marine crews are covered by our Maritime Employers Liability insurance policy which covers Jones Act exposures and includes a deductible of $100,000 per occurrence plus a $1.0 million annual aggregate deductible. In addition to the liability policies described above, we currently carry various layers of Umbrella Liability for total limits of $500 million in excess of primary limits. Our self-insured retention on our medical and health benefits program for employees is $250,000 per participant.

We also maintain Operator Extra Expense coverage that provides up to $150 million of coverage per each loss occurrence for a well control issue. Separately, we also maintain $500 million of liability insurance and $150 million of oil pollution insurance. For any given oil spill event we have up to $650 million of insurance coverage.

We customarily have reciprocal agreements with our customers and vendors in which each contracting party is responsible for its respective personnel. Under these agreements we are indemnified against third party claims related to the injury or death of our customers’ or vendors’ personnel. With respect to well work by our contracting services operations, the customer is generally contractually responsible for pollution emanating from the well. We separately maintain additional coverage for an amount up to $100 million that would cover us under certain circumstances against any such third party claims associated with well control events.

EMPLOYEES

As of December 31, 2013, we had approximately 1,600 employees, of which approximately 765 were salaried personnel. As of December 31, 2013, we also contracted with third parties to utilize 25 non-U.S. citizens to crew our foreign flagged vessels. Our employees do not belong to a union nor are they employed pursuant to any collective bargaining agreement or any similar arrangement. We believe our relationship with our employees and foreign crew members is favorable.

WEBSITE AND OTHER AVAILABLE INFORMATION

We maintain a website on the Internet with the address of www.HelixESG.com. Copies of this Annual Report for the year ended December 31, 2013, and previous and subsequent copies of our Quarterly Reports on Form 10-Q and any Current Reports on Form 8-K, and any amendments thereto, are or will be available free of charge at such website as soon as reasonably practicable after they are filed with, or furnished to, the Securities and Exchange Commission ("SEC"). In addition, the Investor Relations portion of our website contains copies of our Code of Conduct and Business Ethics and our Code of Ethics for Chief Executive Officer and Senior Financial Officers. We make our website content available for informational purposes only. Information contained on our website is not part of this report and should not be relied upon for investment purposes. Please note that prior to March 6, 2006, the name of the Company was Cal Dive International, Inc.

The general public may read and copy any materials we file with the SEC at the SEC's Public Reference Room at 450 Fifth Street, N.W., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. We are an electronic filer, and the SEC maintains an Internet website that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC, including us. The Internet address of the SEC's website is www.sec.gov.

We intend to satisfy the requirement under Item 5.05 of Form 8-K to disclose any amendments to our Code of Conduct and Business Ethics and our Code of Ethics for Chief Executive Officer and Senior Financial Officers and any waiver from any provision of those codes by posting such information in the Investor Relations section of our website at www.HelixESG.com.

CERTAIN DEFINITIONS

Defined below are certain terms helpful to understanding our business that are located through this Annual Report:

BOEM: The Bureau of Ocean Energy Management ("BOEM") is responsible for managing environmentally and economically responsible development of the U.S. offshore resources. Its functions include offshore leasing, resource evaluation, review and administration of oil and gas exploration and development plans, renewable energy development, National Environmental Policy Act analysis and environmental studies.

BSEE: The Bureau of Safety and Environmental Enforcement ("BSEE") is responsible for safety and environmental oversight of offshore oil and gas operations, including permitting and inspections, of offshore oil and gas operations. Its functions include the development and enforcement of safety and environmental regulations, permitting offshore exploration, development and production, inspections, offshore regulatory programs, oil spill response and newly formed training and environmental compliance programs.

Deepwater: Water depths exceeding 1,000 feet.

Dynamic Positioning (DP): Computer directed thruster systems that use satellite based positioning and other positioning technologies to ensure the proper counteraction to wind, current and wave forces enabling the vessel to maintain its position without the use of anchors.

Table of Contents

DP-2: Two DP systems on a single vessel providing the redundancy which allows the vessel to maintain position even with the failure of one DP system, required for vessels which support both manned diving and robotics and for those working in close proximity to platforms. DP-2 is necessary to provide the redundancy required to support safe deployment of divers, while only a single DP system is necessary to support ROV operations.

IRM: Inspection, repair and maintenance.

Life of Field Services: Services performed on offshore facilities, trees and pipelines from the beginning to the end of the economic life of an oil field, including installation, inspection, maintenance, repair, well intervention and abandonment.

QHSE: Quality, Health, Safety and Environmental programs to protect the environment, safeguard employee health and avoid injuries.

Remotely Operated Vehicle (ROV): Robotic vehicles used to complement, support and increase the efficiency of diving and subsea operations and for tasks beyond the capability of manned diving operations.

ROVDrill: ROV deployed coring system developed to take advantage of existing ROV technology. The coring package, deployed with the ROV system, is capable of taking cores from the seafloor in water depths up to 3,000 meters. Because the system operates from the seafloor there is no need for surface drilling strings and the larger support spreads required for conventional coring.

Saturation Diving: Saturation diving, required for work in water depths between 200 and 1,000 feet, involves divers working from special chambers for extended periods at a pressure equivalent to the pressure at the work site.

Spar: Floating production facility anchored to the sea bed with catenary mooring lines.

Spot Market: Prevalent market for subsea contracting in the Gulf of Mexico, characterized by projects that are generally short in duration and often on a turnkey basis. These projects often require constant rescheduling and the availability or interchangeability of multiple vessels.

Subsea Construction Vessels: Subsea services are typically performed with the use of specialized construction vessels which provide an above-water platform that functions as an operational base for divers and ROVs. Distinguishing characteristics of subsea construction vessels include DP systems, saturation diving capabilities, deck space, deck load, craneage and moonpool launching. Deck space, deck load and craneage are important features of a vessel's ability to transport and fabricate hardware, supplies and equipment necessary to complete subsea projects.

Tension Leg Platform (TLP): A floating production facility anchored to the seabed with tendons.

Trencher or Trencher System: A subsea robotics system capable of providing post lay trenching, inspection and burial (PLIB) and maintenance of submarine cables and flowlines in water depths of 30 to 7,200 feet across a range of seabed and environmental conditions.

Well Intervention Services: Activities related to well maintenance and production management/enhancement services. Our well intervention operations include the utilization of slickline and electric line services, pumping services, specialized tooling and coiled tubing services.

Table of Contents

Item 1A. Risk Factors

Shareholders should carefully consider the following risk factors in addition to the other information contained herein. You should be aware that the occurrence of the events described in these risk factors and elsewhere in this Annual Report could have a material adverse effect on our business, results of operations and financial position.

Business Risks

Our results of operations could be adversely affected if our business assumptions do not prove to be accurate or if adverse changes occur in our business environment, including the following areas:

- changes in laws or regulations, including laws relating to the environment or to the oil and gas industry in general, and other factors, many of which are beyond our control;
- general global economic and business conditions, which affect demand for oil and natural gas and, in turn, our business;
- our ability to manage risks related to our business and operations;
- our ability to manage shipyard construction, and upgrades and modifications of our vessels;
- our ability to compete against companies that provide more services and products than we do, including “integrated service companies”;
- our ability to attract and retain skilled, trained personnel to provide technical services and support for our business;
- our ability to procure sufficient supplies of materials essential to our business in periods of high demand, and to reduce our commitments for such materials in periods of low demand; and
- consolidation by our customers, which could result in loss of a customer.

Enhanced regulations for deepwater drilling offshore the United States may reduce the need for our services in the Gulf of Mexico.

Under enhanced safety standards, in order for an operator to conduct deepwater drilling, it is required to comply with existing and newly developed regulations and standards. The BSEE conducts many inspections of deepwater drilling operations for compliance with its regulations, including but not limited to the testing of blowout preventers, before drilling may commence. Operators also need to comply with the Safety and Environmental Management System (SEMS Rule) within the deadlines specified by the regulation, and ensure that their contractors have SEMS compliant safety and environmental policies. Additionally, each operator must demonstrate that it has enforceable obligations that ensure that containment resources are available promptly in the event of a deepwater blowout, regardless of the company or operator involved. It is expected that the BOEM and BSEE will continue to issue further regulations regarding deepwater offshore drilling. Our contracting services business, a significant portion of which is in the Gulf of Mexico, provides development services to newly drilled wells, and therefore relies heavily on the industry’s drilling of new oil and gas wells. With respect to our services business, if the issuance of permits is significantly delayed, or if demand for our services is decreased or delayed because other oil and gas operations are delayed or reduced due to increased costs, demand for our services in the Gulf of Mexico may also decline. Moreover, if our vessels are not redeployed to other locations where we can provide our services at a profitable rate, our business, financial condition and results of operations would be materially affected.

The potential increased costs of complying with new regulations on offshore drilling in the U.S. Gulf of Mexico and potentially in other areas around the world, may impact the need for our services in those areas.

Exploration and development activities and the production and sale of oil and gas are subject to extensive federal, state, local and international regulations. We cannot predict with any certainty the substance or effect of any new or additional regulations in the United States or in other areas around the world including the increase in costs or delays associated with such regulations. If the United States or other countries where we operate enact stricter restrictions on offshore drilling or further regulate offshore drilling and increase costs for our customers, our business, financial condition and results of operations could be materially affected.

Table of Contents

Government Regulation, including recent legislative initiatives, may affect our business operations.

Numerous federal and state regulations affect our operations. Current regulations are constantly reviewed by the various agencies at the same time that new regulations are being considered and implemented, and could include regulations pertaining to contracting service operators such as ourselves. The regulatory burden upon the oil and gas industry increases the cost of doing business and consequently affects our profitability. Potential legislation and/or regulatory actions could increase our costs and reduce our liquidity, delay our operations or otherwise alter the way we conduct our business. Exploration and development activities and the production and sale of oil and gas are subject to extensive federal, state, local and international regulations.

Our operations are subject to a variety of national (including federal, state and local) and international laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Numerous domestic and foreign governmental agencies issue rules and regulations to implement and enforce such laws that are often complex and costly to comply with and that carry substantial administrative, civil and possibly criminal penalties for failure to comply. Under these laws and regulations, we may be liable for remediation or removal costs, damages and other costs associated with releases of hazardous materials, including oil into the environment, and such liability may be imposed on us even if the acts that resulted in the releases were in compliance with all applicable laws at the time such acts were performed.

A variety of regulatory developments, proposals or requirements and legislative initiatives have been introduced in the domestic and international regions in which we operate that are focused on restricting the emission of carbon dioxide, methane and other greenhouse gases. For example, the U.S. Congress has from time to time considered legislation to reduce greenhouse gas emissions, and almost one-half of the states already have taken legal measures to reduce greenhouse gas emissions, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs.

In 2007, the U.S. Supreme Court held in Massachusetts, et al. v. EPA that greenhouse gases are an “air pollutant” under the federal Clean Air Act and thus subject to future regulation. In December 2009, the EPA issued an “endangerment and cause or contribute finding” for greenhouse gases under the federal Clean Air Act, which allowed the EPA to proceed with the adoption and implementation of regulations that would restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act. Since 2009, the EPA has issued regulations that, among other things, require a reduction of emissions of greenhouse gases from motor vehicles and that impose greenhouse gas emission limitations in Clean Air Act permits for certain stationary sources. The EPA has received petitions to regulate greenhouse gas emissions from marine vessels, but we are currently unaware of any rulemaking projects initiated pursuant to the petitions.

Additionally, in October 2009, the EPA published a final rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas sources in the United States on an annual basis, beginning in 2011 for emissions occurring in 2010. In November 2010, the EPA expanded its greenhouse reporting rule to include onshore petroleum natural gas production, offshore petroleum and natural gas production, onshore natural gas processing, natural gas transmission, underground natural gas storage, liquefied natural gas storage, liquefied natural gas import and export, and natural gas distribution facilities. Under these rules, reporting of greenhouse gas emissions from such facilities is required on an annual basis.

These regulatory developments and legislative initiatives may curtail production and demand for fossil fuels such as oil and gas in areas of the world where our customers operate and thus adversely affect future demand for our services, which may in turn adversely affect our future results of operations. In addition, changes in environmental laws and regulations, or claims for damages to persons, property, natural resources or the environment, could result in substantial costs and liabilities, and thus there can be no assurance that we will not incur significant environmental compliance costs in the future. Such environmental liability could substantially reduce our net income and could have a significant impact on our financial ability to carry out our operations.

Table of Contents

The application of the Jones Act (which regulates the kind of vessels that can carry goods between ports of the US) to offshore oil and gas work in the US is interpreted in large part by letter rulings of the U.S. Customs and Border Protection Agency ("CBP"). The cumulative effect of these letter rulings has been to establish a framework for offshore operators to understand when an operation can be carried out by a foreign flag vessel and when it must be carried out by a coastwise qualified US flag vessel. In early 2010, CBP and its parent agency, the Department of Homeland Security ("DHS"), initiated a proposed rulemaking that would have been subject to public comment following publication in the Federal Register. The proposed rulemaking would have largely reversed the holdings of years of letter rulings from the CBP regarding the application of the Jones Act to offshore oil and gas work. The agencies subsequently withdrew the proposed rulemaking before it was published in the Federal Register. If DHS or CBP re-proposes a change to the application of the Jones Act similar to that originally proposed by CBP, and such proposal is adopted, or if CBP issues one or more letter rulings that interprets the Jones Act as being more restrictive to the operation of foreign flag vessels, such a development could potentially lead to operational delays or increased operating costs in instances where we would be required to hire coastwise qualified vessels that we currently do not own, in order to transport certain merchandise to projects on the OCS. This could increase our costs of compliance and doing business and make it more difficult to perform our offshore services in the US.

Economic downturn and lower oil and natural gas prices could negatively impact our business.

Our operations are affected by local, national and worldwide economic conditions and the condition of the oil and gas industry. Certain economic data indicates the global economy faces an uncertain outlook. The consequences of a prolonged period of little or no economic growth will likely result in a lower level of activity and increased uncertainty regarding the direction of energy prices and the capital and commodity markets, which will likely contribute to decreased offshore exploration and drilling. A lower level of offshore exploration and drilling could have a material adverse effect on the demand for our services. In addition, a general decline in the level of economic activity might result in lower commodity prices, which may also adversely affect demand for and revenues from our services. The extent of the impact of these factors on our results of operations and cash flows depends on the length and severity of the decreased demand for our services and lower commodity prices.

Continued market deterioration could also jeopardize the performance of certain counterparty obligations, including those of our insurers, customers and financial institutions. Although we assess the creditworthiness of our counterparties, prolonged business decline or disruptions as a result of economic slow-down or lower commodity prices could lead to changes in a counterparty's liquidity and increase our exposure to credit risk and bad debts. In the event any such party fails to perform, our financial results could be adversely affected and we could incur losses and our liquidity could be negatively impacted.

Our services are adversely affected by low oil and gas prices and by the cyclicality of the oil and gas industry.

Conditions in the oil and natural gas industry are subject to factors beyond our control. Our services are substantially dependent upon the condition of the oil and gas industry, and in particular, the willingness of oil and gas companies to make capital expenditures for offshore exploration, development, drilling and production operations. The level of capital expenditures generally depends on the prevailing view of future oil and gas prices, which are influenced by numerous factors affecting the supply and demand for oil and gas, including, but not limited to:

- worldwide economic activity;
- demand for oil and natural gas, especially in the United States, Europe, China and India;
- economic and political conditions in the Middle East and other oil-producing regions;
- actions taken by OPEC;
- the availability and discovery rate of new oil and natural gas reserves in offshore areas;

- the exploration and production of shale oil and natural gas;
- the cost of offshore exploration for and production and transportation of oil and gas;
- the ability of oil and natural gas companies to generate funds or otherwise obtain external capital for exploration, development and production operations;
- the sale and expiration dates of offshore leases in the United States and overseas;
- technological advances affecting energy exploration, production, transportation and consumption;
- weather conditions;
- environmental and other governmental regulations; and
- tax laws, regulations and policies.

Table of Contents

A sustained period of low drilling and production activity or lower commodity prices would likely have a material adverse effect on our financial position, cash flows and results of operations.

Vessel upgrade, repair and construction projects are subject to risks, including delays, cost overruns, and failure to secure drilling contracts.

We are constructing two newbuild semisubmersible well intervention vessels, the Q5000 and the Q7000. We are also constructing additional ROVs and trenchers. We may also commence the construction of additional vessels for our fleet from time to time without first obtaining service contracts covering any such vessel. Our failure to secure service contracts for vessels under construction prior to deployment could adversely affect our financial position, results of operations and cash flows.

Depending on available opportunities, we may construct additional vessels for our fleet in the future. In addition, we incur significant upgrade, refurbishment and repair expenditures on our fleet from time to time. Some of these expenditures are unplanned. These projects are subject to risks of delay or cost overruns inherent in any large construction project resulting from numerous factors, including the following:

- shortages of equipment, materials or skilled labor;
- unscheduled delays in the delivery of ordered materials and equipment;
- unanticipated increases in the cost of equipment, labor and raw materials, particularly steel;
- weather interferences;
- difficulties in obtaining necessary permits or in meeting permit conditions;
- design and engineering problems;
- political, social and economic instability, war and civil disturbances;
- delays in customs clearance of critical parts or equipment;
- financial or other difficulties or failures at shipyards and suppliers;
- disputes with shipyards and suppliers; and
- work stoppages and other labor disputes.

Delays in the delivery of vessels being constructed or undergoing upgrade, refurbishment or repair may result in delay in contract commencement, resulting in a loss of revenue and cash flow to us, and may cause our customers to seek to terminate or shorten the terms of their contract, or seek delay damages, under applicable late delivery clauses, if any. For example, the recently announced contracts for our chartered vessels in Brazil have penalty provisions for late delivery. In the event of termination of one of these contracts, we may not be able to secure a replacement contract on as favorable terms, if at all. The estimated capital expenditures for vessels, upgrades, refurbishments and construction projects could materially exceed our planned capital expenditures. Moreover, our vessels undergoing upgrade, refurbishment and repair may not earn a day rate during the period they are out-of-service.

Additionally, as vessels age, they are more likely to be subject to higher maintenance and repair activities and thus suffer lower levels of utilization. Any significant period of unplanned maintenance and repairs related to our vessels could materially affect our results of operations and operating cash flows.

Time chartering of our ROV support vessels requires us to make payments regardless of utilization and revenue generation, which could adversely affect our operations.

Most of our ROV support vessels are under long-term time charter contracts. Should we not have work for those vessels, we are still required to make time charter payments, and making those payments absent revenue generation could have an adverse effect on our financial position, results of operations and cash flows.

Our contracting business typically declines in winter, and bad weather in the Gulf of Mexico or North Sea can adversely affect our operations.

Marine operations conducted in the Gulf of Mexico and North Sea are seasonal and depend, in part, on weather conditions. Historically, we have enjoyed our highest vessel utilization rates during the summer and fall when weather conditions are favorable for offshore exploration, development and construction activities. We typically have experienced our lowest utilization rates in the first quarter. As is common in the industry, we may bear the risk of delays caused by some adverse weather conditions. Accordingly, our results in any one quarter are not necessarily indicative of annual results or continuing trends.

Table of Contents

Certain areas in and near the Gulf of Mexico and North Sea experience unfavorable weather conditions including hurricanes and other extreme weather conditions on a relatively frequent basis. Substantially all of our facilities and assets offshore and along the Gulf of Mexico and the North Sea are susceptible to damage and/or total loss by these storms. Damage caused by high winds and turbulent seas could potentially cause us to curtail service operations for significant periods of time until damage can be assessed and repaired. Moreover, even if we do not experience direct damage from any of these storms, we may experience disruptions in our operations because customers may curtail their development activities due to damage to their platforms, pipelines and other related facilities.

Our current backlog for our services may not be ultimately realized, and our contracts may be terminated early.

As of December 31, 2013, backlog for our services supported by written agreements or contracts totaled $2.0 billion, of which $846.0 million is expected to be performed in 2014. Although historically our service contracts were of relatively short duration, over the last several years we have been entering into longer term contracts, specifically in the Gulf of Mexico and more recently, offshore Brazil. As a consequence, we incur capital costs which we expect to recover over the term of the contracts, we charter vessels over the terms of and for the purpose of performing contracts, and/or we forego other contracting opportunities for the term of these contracts. We may not be able to perform under these contracts due to events beyond our control, and because of this and other various reasons, including our perceived non-performance, our customers may seek to cancel, terminate, suspend or renegotiate our contracts. In addition, some of our customers could experience liquidity issues or could otherwise be unable or unwilling to perform under the contract, which could lead a customer to seek to repudiate, cancel or renegotiate a contract. Our inability or the inability of our customers to perform under our or their contractual obligations, or the early cancellation or termination of our contracts by our customers, could have a material adverse effect on our financial position, results of operations and cash flows.

The operation of marine vessels is risky, and we do not have insurance coverage for all risks.

Marine construction involves a high degree of operational risk. Hazards, such as vessels sinking, grounding, colliding and sustaining damage from severe weather conditions, are inherent in marine operations. These hazards can cause personal injury or loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage, and suspension of operations. Damage arising from such occurrences may result in lawsuits asserting large claims. Insurance may not be sufficient or effective under all circumstances or against all hazards to which we may be subject. A successful claim for which we are not fully insured could have a material adverse effect on us. Moreover, we cannot assure you that we will be able to maintain adequate insurance in the future at rates that we consider reasonable. As a result of market conditions, premiums and deductibles for certain of our insurance policies have increased substantially and could escalate further. In some instances, certain insurance could become unavailable or available only for reduced amounts of coverage. For example, insurance carriers are now requiring broad exclusions for losses due to war risk and terrorist acts and limitations for wind storm damages. The current insurance on our vessels, in some cases, is in amounts approximating book value, which could be less than replacement value. In the event of property loss due to a catastrophic marine disaster, mechanical failure, collision or other event, insurance may not cover a substantial loss of revenues, increased costs and other liabilities, and therefore, the loss of any of our large vessels could have a material adverse effect on us.

Our customers may be unable or unwilling to indemnify us.

Consistent with standard industry practice, we typically obtain contractual indemnification from our customers whereby they agree to protect and indemnify us for liabilities resulting from various hazards associated with the drilling industry. We can provide no assurance, however, that our customers will be willing or financially able to meet these indemnification obligations. Also, we may choose not to enforce these indemnities because of business reasons.

Failure to comply with the U.S. Foreign Corrupt Practices Act or foreign anti-bribery legislation could have an adverse impact on our business.

The U.S. Foreign Corrupt Practices Act (the “FCPA”) and similar anti-bribery laws in other jurisdictions, including the United Kingdom Bribery Act 2010, generally prohibit companies and their intermediaries from making improper payments to foreign officials for the purpose of obtaining or retaining

Table of Contents

business. We operate in many parts of the world that have experienced governmental corruption to some degree and, in certain circumstances, strict compliance with anti-bribery laws may conflict with local customs and practices and impact our business. Although we have programs in place covering compliance with anti-bribery legislation, any failure to comply with the FCPA or other anti-bribery legislation could subject us to civil and criminal penalties or other sanctions, which could have a material adverse effect on our business, financial position, results of operations and cash flows, and cause certain reputational damage. We could also face fines, sanctions and other penalties from authorities in the relevant foreign jurisdictions, including prohibition of our participating in or curtailment of business operations in those jurisdictions and the seizure of rigs or other assets.

Lack of access to the credit market could negatively impact our ability to operate our business and to execute our business strategy.

Access to financing may be limited and uncertain, especially in times of economic weakness. If capital and credit markets are limited, we may incur increased costs associated with any additional financing we may require for future operations. Additionally, if capital and credit markets are limited, this could potentially result in our customers curtailing their capital and operating expenditure programs, which could result in a decrease in demand for our vessels and a reduction in fees and/or utilization. In addition, certain of our customers could experience an inability to pay suppliers, including us, in the event they are unable to access capital markets as needed to fund their business operations. Likewise, our suppliers may be unable to sustain their current level of operations, fulfill their commitments and/or fund future operations and obligations, each of which could adversely affect our operations. Continued lower levels of economic activity and weakness in the credit markets could also adversely affect our ability to implement our strategic objectives and dispose of non-core business assets.

Our forward-looking statements assume that our lenders, insurers and other financial institutions will be able to fulfill their obligations under our various credit agreements, insurance policies and contracts. If any of our significant financial institutions were unable to perform under such agreements, and if we were unable to find suitable replacements at a reasonable cost, our results of operations, liquidity and cash flows could be adversely impacted.

Our indebtedness and the terms of our indebtedness could impair our financial condition and our ability to fulfill our debt obligations.

As of December 31, 2013, we had $566.2 million of consolidated indebtedness outstanding. The level of indebtedness may have an adverse effect on our future operations, including:

- limiting our ability to obtain additional financing on satisfactory terms to fund our working capital requirements, capital expenditures, acquisitions, investments, debt service requirements and other general corporate requirements;
- increasing our vulnerability to a continued general economic downturn, competition and industry conditions, which could place us at a disadvantage compared to our competitors that are less leveraged;
- increasing our exposure to potential rising interest rates because a portion of our current and potential future borrowings are at variable interest rates;
- reducing the availability of our cash flows to fund our working capital requirements, capital expenditures, acquisitions, investments and other general corporate requirements because we will be required to use a substantial portion of our cash flows to service debt obligations;
- limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate; and
-

limiting our ability to expand our business through capital expenditures or pursuit of acquisition opportunities due to negative covenants in senior secured credit facilities that place annual and aggregate limitations on the types and amounts of investments that we may make, and limit our ability to use proceeds from asset sales for purposes other than debt repayment (except in certain circumstances where proceeds may be reinvested under criteria set forth in our credit agreements).

Table of Contents

A prolonged period of weak economic activity may make it increasingly difficult to comply with our covenants and other restrictions in agreements governing our debt. Our ability to comply with these covenants and other restrictions may be affected by the economic conditions and other events beyond our control. If we fail to comply with these covenants and other restrictions, it could lead to an event of default, the possible acceleration of our repayment of outstanding debt and the exercise of certain remedies by the lenders, including foreclosure against our collateral.

Our operations outside of the United States subject us to additional risks.

Our operations outside of the United States are subject to risks inherent in foreign operations, including, without limitation:

- the loss of revenue, property and equipment from expropriation, nationalization, war, insurrection, acts of terrorism and other political risks;
- increases in taxes and governmental royalties;
- changes in laws and regulations affecting our operations, including changes in customs, assessments and procedures, and changes in similar laws and regulations that may affect our ability to move our assets in and out of foreign jurisdictions;
- renegotiation or abrogation of contracts with governmental entities;
- changes in laws and policies governing operations of foreign-based companies;
- currency restrictions and exchange rate fluctuations;
- world economic cycles;
- restrictions or quotas on production and commodity sales;
- limited market access; and
- other uncertainties arising out of foreign government sovereignty over our international operations.

In addition, laws and policies of the United States affecting foreign trade and taxation may also adversely affect our international operations.

Our consolidated financial results are reported in U.S. dollars while certain assets and other reported items are denominated in the currencies of other countries, creating currency translation risk.

The reporting currency for our consolidated financial statements is the U.S. dollar. Certain of our assets, liabilities, revenues and expenses are denominated in other countries' currencies. Those assets, liabilities, revenues and expenses are translated into U.S. dollars at the applicable exchange rates to prepare our consolidated financial statements. Therefore, increases or decreases in exchange rates between the U.S. dollar and those other currencies affect the value of those items as reflected in our consolidated financial statements, even if their value remains unchanged in their original currency. Substantial fluctuations in the value of the U.S. dollar could have a significant impact on our results.

We may not be able to compete successfully against current and future competitors.

The oilfield services business in which we operate is highly competitive. Several of our competitors are substantially larger and have greater financial and other resources than we have. If other companies relocate or acquire vessels for operations in the Gulf of Mexico, North Sea, Asia Pacific or West Africa regions, levels of competition may increase and our business could be adversely affected.

In addition, in a few countries, the national oil companies have formed subsidiaries to provide oilfield services for them, competing with services provided by us. To the extent this practice expands, our business could be adversely impacted.

The loss of the services of one or more of our key employees, or our failure to attract and retain other highly qualified personnel in the future, could disrupt our operations and adversely affect our financial results.

Our industry has lost a significant number of experienced professionals over the years due to its cyclical nature, which is attributable, among other reasons, to the volatility in commodity prices. Our continued success depends on the active participation of our key employees. The loss of our key people could adversely affect our operations.

Table of Contents

In addition, the delivery of our services requires personnel with specialized skills and experience. As a result, our ability to remain productive and profitable will depend upon our ability to employ and retain skilled workers. Our ability to expand our operations depends in part on our ability to increase the size of our skilled labor force. The demand for skilled workers in our industry is high, and the supply is limited. In addition, although our employees are not covered by a collective bargaining agreement, the marine services industry has in the past been targeted by maritime labor unions in an effort to organize Gulf of Mexico employees. A significant increase in the wages paid by competing employers or the unionization of our Gulf of Mexico employees could result in a reduction of our labor force, increases in the wage rates that we must pay or both. If either of these events were to occur, our capacity and profitability could be diminished and our growth potential could be impaired.

If we fail to effectively manage our growth strategy, our results of operations could be harmed.

Our current strategy is to expand our well intervention and robotics businesses. We must plan and manage our growth effectively to achieve increased revenue and maintain profitability in our evolving market. If we fail to effectively manage current and future growth, our results of operations could be adversely affected. In the past, our growth has placed significant demands on our personnel, management and other resources. We must continue to improve our operational, financial, management and legal compliance information systems to keep pace with the planned expansion of our services.

Information security breaches or business system disruptions may adversely affect our business.

We rely on our information technology infrastructure and management information systems to operate and record aspects of our business. Although we take measures to protect our information assets, our security measures may not detect or prevent every attempted breach. We may be subject to information security breaches caused by, among other things, illegal hacking, computer viruses, or acts of vandalism or terrorism. A breach could result in an interruption in our operations, unauthorized publication of our confidential business or proprietary information, unauthorized release of customer or employee data, violation of privacy or other laws, and exposure to litigation. Any such breach could materially harm our business and operating results.

Certain provisions of our corporate documents and Minnesota law may discourage a third party from making a takeover proposal.

Our Articles of Incorporation give our Board of Directors the authority, without any action by our shareholders, to fix the rights and preferences on up to 4,994,000 shares of undesignated preferred stock, including dividend, liquidation and voting rights. In addition, our by-laws divide the Board of Directors into three classes. We are also subject to certain anti-takeover provisions of the Minnesota Business Corporation Act. We also have employment arrangements with all of our executive officers that require cash payments in the event of a “change of control.” Any or all of the provisions or factors described above may discourage a takeover proposal or tender offer not approved by management and the Board of Directors and could result in shareholders who may wish to participate in such a proposal or tender offer receiving less for their shares than otherwise might be available in the event of a takeover attempt.

Other Risks

Other risk factors could cause actual results to be different from the results we expect. The market price for our common stock, as well as other companies in the oil and natural gas industry, has been historically volatile, which could restrict our access to capital markets in the future. Other risks and uncertainties may be detailed from time to time in our filings with the SEC.

Many of these risks are beyond our control. In addition, future trends for pricing, margins, revenue and profitability remain difficult to predict in the industries we serve and under current market, economic and political conditions. Forward-looking statements speak only as of the date they are made and, except as required by applicable law, we do not assume any responsibility to update or revise any of our forward-looking statements.

Table of Contents

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

OUR VESSELS

We own a fleet of five vessels and 51 ROVs, four trenchers, and two ROVDrills. We also lease six vessels. Currently all of our vessels, both owned and chartered, have DP capabilities specifically designed to respond to the deepwater market requirements. Our Seawell and Well Enhancer vessels have built-in saturation diving systems.

Listing of Vessels and Robotics Assets Related to Operations (1)

	Flag State	Placed in Service (2)	Length (Feet)	Berths	SAT Diving	DP	Crane Capacity (tons)
Floating Production Unit —							
Helix Producer I (4)	Bahamas	4/2009	528	95	—	DP	26 and 26
Well Intervention —							
Q4000 (5)	U.S.	4/2002	312	135	—	DP	160 and 360; 600 Derrick
Seawell	U.K.	7/2002	368	129	Capable	DP	65 and 130; 80 Derrick
Well Enhancer	U.K.	10/2009	432	120	Capable	DP	100; 150 Derrick
Skandi Constructor (7)	Bahamas	4/2013	395	100	—	DP	150; 140 Derrick
Helix 534	Panama	2/2014	534	156	—	DP	600 Derrick
Robotics —							
51 ROVs, 4 Trenchers and 2 ROVDrills (3), (6)	—	Various	—	—	—	—	—
Olympic Canyon (7)	Norway	4/2006	304	87	—	DP	150
Olympic Triton (7)	Norway	11/2007	311	87	—	DP	150
Deep Cygnus (7)	Panama	4/2010	400	92	—	DP	150 and 25
Grand Canyon (7)	Panama	10/2012	419	104	—	DP	250
Rem Installer (7)	Norway	7/2013	353	110	—	DP	250

(1) Under government regulations and our insurance policies, we are required to maintain our vessels in accordance with standards of seaworthiness and safety set by government regulations and classification organizations. We maintain our fleet to the standards for seaworthiness, safety and health set by the ABS, Bureau Veritas (“BV”), Det Norske Veritas (“DNV”), Lloyds Register of Shipping (“Lloyds”), and the USCG. ABS, BV, DNV and Lloyds are classification societies used by ship owners to certify that their vessels meet certain structural, mechanical and safety equipment standards.

(2) Represents the date we placed the vessel in service and not the date of commissioning.

(3) Subject to security agreements securing our Credit Agreement described in Note 7.

(4) Following the initial conversion of this vessel from a former ferry vessel into a DP floating production unit, additional topside production equipment was added to the vessel and it was certified for oil and natural gas processing work in June 2010 (see "Production Facilities"). The topside production equipment is subject to security agreements securing our Credit Agreement (Note 7).

(5) Subject to vessel mortgage securing our MARAD debt described in Note 7.

(6) Average age of our fleet of ROVs, trenchers and ROVDrills is approximately 6.7 years.

(7) Leased.

Table of Contents

The following table details the average utilization rate for our vessels by category (calculated by dividing the total number of days the vessels in this category generated revenues by the total number of calendar days in the applicable period) for the years ended December 31, 2013, 2012 and 2011:

	Year Ended December 31,		
	2013	2012	2011
Well Intervention vessels	92%	82%	90%
ROVs	63%	67%	60%
Robotics vessels	88%	92%	92%
Subsea Construction vessels	92%	84%	54%

We incur routine dry dock, inspection, maintenance and repair costs pursuant to Coast Guard regulations in order to maintain our vessels in class under the rules of the applicable class society. The reduced well intervention utilization in 2012 reflects the downtime associated with the regulatory dry docks for our Q4000, Seawell and Well Enhancer vessels. In addition to complying with these requirements, we have our own vessel maintenance program that we believe permits us to continue to provide our customers with well maintained, reliable vessels. In the normal course of business, we charter other vessels on a short-term basis, such as tugboats, cargo barges, utility boats and additional robotics support vessels. The reduction in ROV and robotics vessel utilization in 2013 primarily reflects greater than usual seasonal declines in the North Sea in early 2013, and lower year-over-year trenching activities associated with the deferral of many previously anticipated 2013 trenching projects in the North Sea region until 2014 and beyond. The subsea construction vessel utilization in 2013 is attributed to the Caesar and the Express prior to the sale of these two vessels in mid-2013.

PRODUCTION FACILITIES

We own a 50% interest in Deepwater Gateway, a limited liability company in which Enterprise Products Partners L.P. is the other member. Deepwater Gateway was formed to construct, install and own the Marco Polo TLP in order to process production from Anadarko Petroleum Corporation’s Marco Polo field discovery at Green Canyon Block 608, which is located in water depths of 4,300 feet. Anadarko required processing capacity of 50,000 barrels of oil per day and 150 MMcf of natural gas per day for its Marco Polo field. The Marco Polo TLP was designed to process 120,000 barrels of oil per day and 300 MMcf of natural gas per day and payload with space for up to six subsea tiebacks.

We also own a 20% interest in Independence Hub, an affiliate of Enterprise Products Partners L.P., that owns the Independence Hub platform, a 105-foot deep draft, semi-submersible platform located in Mississippi Canyon Block 920 in a water depth of 8,000 feet. Since July 2007, Independence Hub has served as a regional hub for natural gas production from multiple ultra-Deepwater fields in the eastern Gulf of Mexico. The Independence Hub facility is capable of processing up to one Bcf per day of gas.

Further, we, along with Kommandor Rømø, a Danish corporation, formed Kommandor LLC and converted a ferry vessel into the HP I, a dynamically positioned floating production vessel. The initial conversion of the HP I was completed in April 2009, and we have chartered the vessel from Kommandor LLC. As of December 31, 2013, we owned approximately 81% of Kommandor LLC. We have recently reached agreement with Kommandor Rømø to acquire its noncontrolling interests in Kommandor LLC for $20.1 million.

After the initial conversion and our subsequent charter of the HP I, we installed, at 100% our cost, processing facilities and a disconnectable fluid transfer system on the vessel. The HP I is capable of processing up to 45,000 barrels of oil and 80 MMcf of natural gas daily. The initial deployment of the HP I was for use in the Macondo well control and containment efforts. Following those efforts, the HP I mobilized to the Phoenix field and has been processing its production since October 2010. The HP I is contracted to remain in the Phoenix field through at least December 31, 2016. The results of Kommandor LLC and the HP I are consolidated within our Production Facilities business segment (Note 14).

Table of Contents

FACILITIES

Our corporate headquarters are located at 3505 West Sam Houston Parkway North, Suite 400, Houston, Texas. We own the Aberdeen (Dyce), Scotland facility and lease our other facilities. The list of our facilities as of January 31, 2014 is as follows:

Location	Function	Size
Houston, Texas	Helix Energy Solutions Group, Inc. Corporate Headquarters, Project Management, and Sales Office	118,630 square feet (including 30,104 square feet under a four-year sub-lease to a third party)
	Helix Subsea Construction, Inc. Corporate Headquarters	
	Helix Well Ops, Inc. Corporate Headquarters, Project Management and Sales Office	
	Canyon Offshore, Inc. Corporate, Management and Sales Office	
	Kommandor LLC Corporate Headquarters	
Houston, Texas	Canyon Offshore, Inc. Warehouse and Storage Facility	3.7 acres (Building: 22,000 square feet)
Aberdeen, Scotland	Helix Well Ops (U.K.) Limited Corporate Offices and Operations	27,000 square feet
Aberdeen (Dyce), Scotland	Canyon Offshore Limited Corporate Offices, Operations and Sales Office	3.9 acres (Building: 42,463 square feet, including 7,000 square feet under a three-year sub-lease to a third party)
	Energy Resource Technology (U.K). Limited Corporate Offices	
Singapore	Canyon Offshore International Corp Corporate, Operations and Sales Office	22,486 square feet
	Helix Offshore Crewing Service Pte. Ltd. Corporate Headquarters	

Item 3. Legal Proceedings

On July 8, 2011, a shareholder derivative lawsuit styled City of Sterling Heights Police & Fire Retirement System v. Owen Kratz, et al. was filed in the United States District Court for the Southern District of Texas, Houston Division. In the suit, the plaintiff makes claims against our Board of Directors, certain of our former directors, certain of our current and former executives, and the independent compensation consultant to the Compensation Committee of our Board of Directors, for breaches of the fiduciary duty of loyalty, unjust enrichment and aiding and abetting the alleged breaches of fiduciary duty relating to the long-term equity awards granted in 2010 to the Company's then executive officers who are defendants. The defendants filed a motion to dismiss the claim asserting that the plaintiff has not (i) pled specific facts excusing its failure to make pre-suit demand on our Board of Directors as required by Minnesota law; (ii) filed proper verification; or (iii) stated a claim. A ruling regarding the motion is pending.

On May 12, 2012, a shareholder derivative lawsuit styled Mark Lucas v. Owen Kratz, et al. was filed in the 270th Judicial District in the District Court of Harris County, Texas. In the suit, the plaintiff makes claims against our Board of Directors, certain of our former directors, certain of our current and former executive officers and the independent compensation consultant to the Compensation Committee of our Board of Directors, for breaches of the fiduciary duties of candor, good faith and loyalty, unjust enrichment and aiding and abetting the alleged breaches of fiduciary duty relating to the long-term equity awards granted in 2010 to certain of our executive officers. This case is essentially a "copycat" complaint asserting similar causes of action arising out of the same facts as set forth in the federal action described above. The plaintiff is generally demanding disgorgement of the excessive compensation, restraint on the

Table of Contents

disposition/exercise of the alleged improperly awarded equity, implementation of additional internal controls, and attorney's fees and costs of litigation. The defendants filed motions to stay and dismiss the proceeding, which motions were denied by the trial court judge. The defendants then filed a petition for a writ of mandamus with the state appellate court, in which they requested that court to direct the district court to grant the motion to stay or dismiss the case. The appellate court denied the request to grant mandamus with respect to this requested relief, but did grant a writ of mandamus ordering the lower court to vacate its ruling to the extent the plaintiff failed to plead with particularity that our Board of Directors wrongfully refused his demand, and that he was a shareholder of record at the relevant time. A special committee of our Board of Directors has since determined to reject the plaintiff's demand regarding this matter, and based on this rejection, as well as the plaintiff's pleadings, the defendants filed a motion for summary judgment in December 2013, which is pending before the court.

We are currently undergoing a value added tax ("VAT") audit from the State of Andhra Pradesh, India (the "State") for the tax years 2010, 2009, 2008 and 2007 related to an Indian subsea construction and diving contract that we entered into in December 2006. We believe that we have complied with all rules and regulations as related to VAT in the State and we anticipate no additional assessments as a result of this audit.

Item 4. Mine Safety Disclosures

Not applicable.

Executive Officers of the Company

The executive officers of Helix are as follows:

Name	Age	Position
Owen Kratz	59	President and Chief Executive Officer and Director
Anthony Tripodo	61	Executive Vice President and Chief Financial Officer
Clifford V. Chamblee	54	Executive Vice President and Chief Operating Officer
Alisa B. Johnson	56	Executive Vice President, General Counsel and Corporate Secretary

Owen Kratz is President and Chief Executive Officer of Helix. He was named Executive Chairman in October 2006 and served in that capacity until February 2008 when he resumed the position of President and Chief Executive Officer. He was appointed Chairman in May 1998 and served as the Company's Chief Executive Officer from April 1997 until October 2006. Mr. Kratz served as President from 1993 until February 1999, and has served as a Director since 1990. He served as Chief Operating Officer from 1990 through 1997. Mr. Kratz joined Helix in 1984 and held various offshore positions, including saturation diving supervisor, and management responsibility for client relations, marketing and estimating. From 1982 to 1983, Mr. Kratz was the owner of an independent marine construction company operating in the Bay of Campeche. Prior to 1982, he was a superintendent for Santa Fe and various international diving companies, and a diver in the North Sea. From February 2006 to December 2011, Mr. Kratz was a member of the Board of Directors of Cal Dive International, Inc., a publicly-traded company, which was formerly a subsidiary of Helix. Mr. Kratz has a Bachelor of Science degree from State University of New York (SUNY).

Anthony Tripodo was elected as Executive Vice President and Chief Financial Officer of Helix on June 25, 2008. Mr. Tripodo oversees the finance, treasury, accounting, tax, information technology and corporate planning functions. Mr. Tripodo was a director of Helix from February 2003 until June 2008. Prior to joining Helix, Mr. Tripodo was the Executive Vice President and Chief Financial Officer of Tesco Corporation. From 2003 through the end of 2006, he was a Managing Director of Arch Creek Advisors LLC, a Houston based investment banking firm. From 1997 to 2003, Mr. Tripodo was Executive Vice President of Veritas DGC, Inc., an international oilfield service company specializing in geophysical services, including serving as Executive Vice President, Chief Financial Officer and Treasurer of Veritas from 1997 to 2001. Previously, Mr. Tripodo served 16 years in various executive capacities with Baker Hughes, including serving as Chief Financial Officer of both the Baker Performance Chemicals and Baker Oil Tools divisions. Mr. Tripodo also has served as a director of three publicly-traded companies in the oilfield services industry in addition to his prior service as a director of Helix. He graduated Summa Cum Laude with a Bachelor of Arts degree from St. Thomas University (Miami).

Table of Contents

Clifford V. Chamblee is Executive Vice President and Chief Operating Officer of Helix. He joined the Company in its robotics subsidiary, Canyon Offshore, Inc. (Canyon), in 1997. Mr. Chamblee served as President of Canyon from 2006 until 2011. Prior to becoming President of Canyon, Mr. Chamblee held several positions with increasing responsibilities at Canyon managing the operations of the company including as Senior Vice President and Vice President Operations from 1997 until 2006. Mr. Chamblee has been involved in the robotics industry for over 32 years. From 1988 to 1997, Mr. Chamblee held various positions with Sonsub International, Inc., including Vice President Remote Systems, Marketing Manager and Operations Manager. From 1986 until 1988, he was Operations Manager and Superintendent for Helix (then known as Cal Dive). From 1981 until 1986, Mr. Chamblee held various positions for Oceaneering International/Jered, including ROV Superintendent and ROV Supervisor. Prior to 1981, he was an ROV Technician for Martech International.

Alisa B. Johnson joined the Company as Senior Vice President, General Counsel and Secretary of Helix in September 2006, and in November 2008 became Executive Vice President, General Counsel and Secretary of the Company. Ms. Johnson oversees the legal, human resources and contracts and insurance functions. Ms. Johnson has been involved with the energy industry for over 23 years. Prior to joining Helix, Ms. Johnson worked for Dynegy Inc. for nine years, at which company she held various legal positions of increasing responsibility, including Senior Vice President and Group General Counsel — Generation. From 1990 to 1997, Ms. Johnson held various legal positions at Destec Entergy, Inc. Prior to that Ms. Johnson was in private law practice. Ms. Johnson received her Bachelor of Arts degree Cum Laude from Rice University and her law degree Cum Laude from the University of Houston.

PART II

Item 5. Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Our common stock is traded on the New York Stock Exchange ("NYSE") under the symbol "HLX." The following table sets forth, for the periods indicated, the high and low sale prices per share of our common stock:

	Common Stock Prices	
	High	Low
2012		
First Quarter	$19.98	$15.55
Second Quarter	$21.09	$14.90
Third Quarter	$20.81	$16.20
Fourth Quarter	$20.83	$15.54
2013		
First Quarter	$25.49	$20.59
Second Quarter	$25.99	$20.33
Third Quarter	$27.58	$23.12
Fourth Quarter	$25.85	$21.33
2014		
First Quarter (1)	$23.13	$19.44

(1) Through February 18, 2014

On February 18, 2014, the closing sale price of our common stock on the NYSE was $21.99 per share. As of February 18, 2014, there were 365 registered shareholders and approximately 23,000 beneficial shareholders of our common stock.

We have never declared or paid cash dividends on our common stock and do not intend to pay cash dividends in the foreseeable future. We currently intend to retain earnings, if any, for the future operation and growth of our business. In addition, our financing arrangements prohibit the payment of cash dividends on our common stock. See Management's Discussion and Analysis of Financial Condition and Results of Operations "— Liquidity and Capital Resources."

Shareholder Return Performance Graph

The following graph compares the cumulative total shareholder return on our common stock for the period since December 31, 2008 to the cumulative total shareholder return for (i) the stocks of 500 large-cap corporations maintained by Standard & Poor's ("S&P 500"), assuming the reinvestment of dividends; (ii) the Philadelphia Oil Service Sector index (the "OSX"), a price-weighted index of leading oil service companies, assuming the reinvestment of dividends; and (iii) a peer group selected by us (the "Peer Group") consisting of the following companies: Atwood Oceanics Inc., Dril-Quip, Inc., GulfMark Offshore, Inc., Hercules Offshore, Inc., Hornbeck Offshore Services, Inc., McDermott International, Inc., Oceaneering International, Inc., Oil States International, Inc., Rowan Companies, Inc., Superior Energy Services, Inc., TETRA Technologies, Inc., and Tidewater Inc. The returns of each member of the Peer Group have been weighted according to each individual company's equity market capitalization as of December 31, 2013 and have been adjusted for the reinvestment of any dividends. We believe that the members of the Peer Group provide services and products more comparable to us than those companies included in the OSX. The graph assumes $100 was invested on December 31, 2008 in our common stock at the closing price on that date price and on December 31, 2008 in the three indices presented. We paid no cash dividends during the period presented. The cumulative total percentage returns for the period presented are as follows: our stock — 220.2%; the Peer Group — 161.1%; the OSX — 131.5%; and S&P 500 — 128.2%. These results are not necessarily indicative of future performance.

Comparison of Five Year Cumulative Total Return among Helix, S&P 500,
OSX and Peer Group

	As of December 31,					
	2008	2009	2010	2011	2012	2013
Helix	$ 100.0	$ 162.3	$ 167.7	$ 218.2	$ 285.1	$ 320.2
Peer Group Index	$ 100.0	$ 178.4	$ 214.9	$ 202.0	$ 200.9	$ 261.1
Oil Service Index	$ 100.0	$ 160.6	$ 201.9	$ 178.2	$ 181.4	$ 231.5
S&P 500	$ 100.0	$ 126.5	$ 145.5	$ 148.6	$ 172.4	$ 228.2

Source: Bloomberg

Issuer Purchases of Equity Securities

Period	(a) Total number of shares purchased (1)	(b) Average price paid per share	(c) Total number of shares purchased as part of publicly announced program (2)	(d) Maximum number of shares that may yet be purchased under the program (2) (3)
October 1 to October 31, 2013	—	$ —	—	—
November 1 to November 30, 2013	—	—	157,705	—
December 1 to December 31, 2013	274	22.51	53,358	—
	274	$ 22.51	211,063	—

Table of Contents

(1) Includes shares delivered to the Company by employees in satisfaction of minimum withholding taxes upon vesting of restricted shares.

(2) Under the terms of our stock repurchase program, the issuance of shares to members of our Board of Directors and to certain employees, including shares issued to our employees under the Employee Stock Purchase Plan (the "ESPP") (Note 9), increases the number of shares available for repurchase. The shares purchased in November represent the ESPP shares issued to our employees in 2013 and the shares purchased in December reflect shares issued to our Board members. For additional information regarding our stock repurchase program, see Note 11.

(3) In January 2014, we issued approximately 0.1 million shares to our executive officers. These grants will increase the number of shares available for repurchase by a corresponding amount (Note 9).

Item 6. Selected Financial Data.

The financial data presented below for each of the five years ended December 31, 2013 should be read in conjunction with Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and Item 8. Financial Statements and Supplementary Data included elsewhere in this Annual Report. In February 2013, we sold ERT. Accordingly, the results associated with our former Oil and Gas segment are presented as discontinued operations for all periods presented in this Annual Report.

	Year Ended December 31,				
	2013	2012	2011	2010	2009 (1)
	(in thousands, except per share amounts)				
Net revenues	$876,561	$846,109	$702,000	$774,469	$1,077,312
Gross profit	260,685	49,915	149,683	164,817	218,623
Income (loss) from operations (2)	179,034	(68,483)	63,040	51,079	101,693
Equity in earnings of investments	2,965	8,434	22,215	19,469	32,329
Net income (loss) from continuing operations	111,976	(66,840)	37,816	(17,496)	110,728
Income (loss) from discontinued operations, net of tax (3)	1,073	23,684	95,221	(106,657)	65,023
Net income (loss), including noncontrolling interests (4)	113,049	(43,156)	133,037	(124,153)	175,751
Net (income) loss applicable to noncontrolling interests	(3,127)	(3,178)	(3,098)	(2,835)	(19,697)
Net income (loss) applicable to Helix	109,922	(46,334)	129,939	(126,988)	156,054
Preferred stock dividends (5)	—	(37)	(40)	(114)	(54,187)
Adjusted EBITDA from continuing operations (6)	268,311	233,612	178,953	160,250	183,088
Adjusted EBITDAX (6)	$300,065	$600,828	$668,662	$430,326	$546,383
Basic earnings (loss) per share of common stock:					
Continuing operations	$1.03	$(0.67)	$0.33	$(0.19)	$0.36
Discontinued operations	0.01	0.23	0.90	(1.03)	0.65
Net income (loss) per common share	$1.04	$(0.44)	$1.23	$(1.22)	$1.01
Diluted earnings (loss) per share of common stock:					

Continuing operations	$1.03	$(0.67)	$0.33	$(0.19)	$0.35
Discontinued operations	0.01	0.23	0.90	(1.03)	0.62
Net income (loss) per common share	$1.04	$(0.44)	$1.23	$(1.22)	$0.97
Weighted average common shares outstanding:					
Basic	105,032	104,449	104,528	103,857	99,136
Diluted	105,184	104,449	104,953	103,857	105,720

Table of Contents

(1) Excludes the results of Cal Dive subsequent to June 10, 2009 following its deconsolidation from our consolidated financial statements.

(2) Amount in 2012 includes impairment charges of approximately $177.1 million, including $14.6 million for the Intrepid, $157.8 million for the Caesar and related mobile pipelay equipment, and $4.6 million for well intervention assets associated with our former operations in Australia (Note 2).

(3) Oil and gas property impairment charges and asset retirement obligation overruns totaled $144.3 million in 2012, including the $138.6 million charge to reduce the value of ERT's properties to their estimated fair value in connection with the announcement of the sale of ERT in December 2012, $112.6 million in 2011, $176.1 million in 2010 and $120.6 million in 2009. Also includes exploration expenses totaling $3.5 million in 2013, $3.3 million in 2012, $10.9 million in 2011, $8.3 million in 2010 and $24.4 million in 2009.

(4) In 2009, we had $77.3 million of gains on the sale of Cal Dive common stock held by us.

(5) Amount in 2009 includes $53.4 million of beneficial conversion charges related to our then outstanding convertible preferred stock.

(6) This is a non-GAAP financial measure. Amounts in 2009 include $56.3 million associated with our ownership in Cal Dive through June 2009 as discussed in footnote (1) above. See "Non-GAAP Financial Measures" below for an explanation of the definition and use of such measure as well as a reconciliation of these amounts to each year's respective reported net income (loss) from continuing operations.

	2013	2012	December 31, 2011 (in thousands)	2010	2009
Working capital	$553,427	$351,061	$548,066	$373,057	$197,072
Total assets (1)	2,544,280	3,386,580	3,582,347	3,592,020	3,779,533
Long-term debt (including current maturities)	566,152	1,019,228	1,155,321	1,357,932	1,360,739
Convertible preferred stock (2)	—	—	1,000	1,000	6,000
Total controlling interest shareholders' equity	1,499,051	1,393,385	1,421,403	1,260,604	1,405,257
Noncontrolling interests	25,059	26,029	28,138	25,040	22,205
Total equity	1,524,110	1,419,414	1,449,541	1,285,644	1,427,462

(1) Includes assets of discontinued oil and gas operations.

(2) In 2012, the holder of our convertible preferred stock converted the remaining $1 million of the convertible preferred stock into 0.4 million shares of our common stock (Note 2). In 2010, the holder of the convertible preferred stock converted $5 million of our convertible preferred stock into 1.8 million shares of our common stock.

Non-GAAP Financial Measures

A non-GAAP financial measure is generally defined by the SEC as a numerical measure of a company's historical or future performance, financial position, or cash flows that includes or excludes amounts from the most directly comparable measure under U.S. generally accepted accounting principles ("GAAP"). We measure our operating performance based on EBITDA, a non-GAAP financial measure that is commonly used but is not a recognized accounting term under GAAP. We use EBITDA to monitor and facilitate the internal evaluation of the performance of our business operations, to facilitate external comparison of our business results to those of others in our industry, to analyze and evaluate financial and strategic planning decisions regarding future investments and acquisitions, to plan and evaluate operating budgets, and in certain cases, to report our results to the holders of our debt as required under our debt covenants. We believe our measure of EBITDA provides useful information to the public regarding our ability to service debt and fund capital expenditures and may help our investors understand our operating performance and compare our results to other companies that have different financing, capital and tax structures.

Table of Contents

We define EBITDA as net income (loss) from continuing operations plus income taxes, net interest expense and other and depreciation and amortization expense. We separately disclose our non-cash asset impairment charges, which, if not material, would be reflected as a component of our depreciation and amortization expense. Because such impairment charges are material for most of the periods presented, we have reported them as a separate line item in the accompanying consolidated statements of operations. Non-cash impairment charges related to goodwill are also added back if applicable. Loss on early extinguishment of long-term debt is considered equivalent to additional interest expense and thus is added back to net income (loss) from continuing operations.

In our reconciliation of income (loss), including noncontrolling interests, we provide amounts as reflected in our accompanying consolidated financial statements unless otherwise footnoted. This means that such amounts are recorded at 100% even if we do not own 100% of all of our subsidiaries. Accordingly, to arrive at our measure of Adjusted EBITDA from continuing operations, when applicable, we deduct the noncontrolling interests related to the adjustment components of EBITDA and the gain or loss on the sale of assets from continuing operations.

We also provide a measure of Adjusted EBITDAX, which combines our measure of Adjusted EBITDA from continuing operations and the measure of Adjusted EBITDAX from discontinued operations. Our discontinued operations primarily consist of ERT which was sold in February 2013. We define Adjusted EBITDAX from discontinued operations as income (loss) from discontinued operations, net of tax (Note 3) plus income taxes, net interest expense and other, depreciation, depletion, amortization and accretion expense and exploration expenses.

Other companies may calculate their measures of EBITDA, Adjusted EBITDA and Adjusted EBITDAX differently than we do, which may limit their usefulness as comparative measures. Because EBITDA is not a financial measure calculated in accordance with GAAP, it should not be considered in isolation or as a substitute for net income (loss) attributable to common shareholders or cash flows from operations, but used as a supplement to these GAAP financial measures. The reconciliation of our net income (loss) from continuing operations to EBITDA from continuing operations, Adjusted EBITDA from continuing operations and Adjusted EBITDAX is as follows:

	Year Ended December 31,				
	2013	2012	2011 (in thousands)	2010	2009
Net income (loss) from continuing operations	$111,976	$(66,840)	$37,816	$(17,496)	$110,728
Adjustments:					
Income tax provision (benefit)	31,612	(59,158)	(36,806)	19,166	68,867
Net interest expense and other	32,892	48,822	71,328	66,638	31,770
Loss on extinguishment of long-term debt	12,100	17,127	2,354	—	—
Depreciation and amortization	98,535	97,201	91,188	81,878	95,960
Asset impairment charges (1)	—	177,135	17,127	23,060	1,305
EBITDA from continuing operations	287,115	214,287	183,007	173,246	308,630
Adjustments:					
Noncontrolling interest Cal Dive	—	—	—	—	(44,785)
Noncontrolling interest Kommandor LLC	(4,077)	(4,128)	(4,060)	(3,878)	(3,344)
Unrealized loss on commodity derivative contracts	—	9,977	—	—	—
(Gain) loss on sale of assets	(14,727)	13,476	6	(9,118)	(77,413)
ADJUSTED EBITDA from continuing operations (2)	$268,311	$233,612	$178,953	$160,250	$183,088
	$268,311	$233,612	$178,953	$160,250	$183,088

ADJUSTED EBITDA from continuing operations					
ADJUSTED EBITDAX from discontinued operations (3)	31,754	367,216	489,709	270,076	363,295
ADJUSTED EBITDAX	$300,065	$600,828	$668,662	$430,326	$546,383

32

Table of Contents

(1) Amount in 2012 includes impairment charges of $14.6 million for the Intrepid, $157.8 million for the Caesar and related mobile pipelay equipment, and $4.6 million for well intervention assets associated with our former operations in Australia (Note 2). Amount in 2011 includes a $6.6 million impairment charge related to our well intervention equipment in Australia and a $10.6 million other than temporary impairment loss on our former equity investment in our Australian joint venture (Note 5). Amount in 2010 includes $16.7 million related to goodwill impairment of our Australian well intervention subsidiary ("WOSEA") and a $2.2 million other than temporary impairment associated with Cal Dive.

(2) Amount in 2009 includes $56.3 million associated with our ownership in Cal Dive prior to its deconsolidation in June 2009.

(3) Amounts relate to ERT which was sold in February 2013 (Notes 1 and 3), and Helix RDS Limited, our former reservoir technology consulting company that we sold in April 2009.

	Year Ended December 31,				
	2013	2012	2011	2010	2009
	(in thousands)				
Income (loss) from discontinued operations, net of tax	$1,073	$23,684	$95,221	$(106,657)	$65,023
Adjustments:					
Income tax provision (benefit)	579	13,420	51,709	(58,764)	24,957
Net interest expense and other	2,732	28,191	25,558	19,671	19,606
Depreciation and amortization	1,226	158,284	219,915	235,243	167,235
Asset impairment charges	—	138,628	112,636	176,089	120,550
Exploration expenses	3,514	3,295	10,914	8,276	24,383
EBITDAX from discontinued operations	9,124	365,502	515,953	273,858	421,754
Adjustments:					
(Gain) loss on sale of assets	22,630	1,714	(4,531)	(287)	(10,281)
Asset retirement costs	—	—	(21,713)	(3,495)	(48,178)
ADJUSTED EBITDAX from discontinued operations	$31,754	$367,216	$489,709	$270,076	$363,295

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following management's discussion and analysis should be read in conjunction with our historical consolidated financial statements located in Item 8. "Financial Statements and Supplementary Data" of this Annual Report. Any reference to Notes in the following management's discussion and analysis refers to the Notes to Consolidated Financial Statements located in Item 8. "Financial Statements and Supplementary Data" of this Annual Report. The results of operations reported and summarized below are not necessarily indicative of future operating results. This discussion also contains forward-looking statements that reflect our current views with respect to future events and financial performance. Our actual results may differ materially from those anticipated in these forward-looking statements as a result of certain factors, such as those set forth under Item 1A. "Risk Factors" and located earlier in this Annual Report.

Executive Summary

Our Business Strategy

We are an international offshore energy company that provides specialty services to the offshore energy industry, with a focus on well intervention and robotics operations. Since 2008 we have focused on improving our balance sheet and increasing our liquidity through dispositions of non-core business assets and the related repayment of a significant portion of our indebtedness, as well as the reduction in our capital spending through 2011. We have substantially finalized this process with the sale of ERT in February 2013 and the sale of our two remaining pipelay vessels in mid-2013. As such, we believe that we are now positioned for growth and expansion.

Our focus is on expanding our well intervention and robotics businesses. We believe that focusing on these services will deliver higher long-term financial returns to us than the businesses and assets that we have chosen to monetize. We are making strategic investments that expand our service capabilities or add capacity to existing services in our key operating regions. Our well intervention fleet has expanded with the newly converted well intervention vessel, the Helix 534, being placed in service in February 2014 and the chartering of the Skandi Constructor, which has been fully equipped and integrated into our North Sea well intervention operations. Our well intervention fleet will expand following the completion of the two newbuild semisubmersible vessels currently under construction, the Q5000 and the Q7000, and the delivery of two newbuild chartered monohull vessels in connection with the recently announced agreements with Petrobras. In addition, we are expanding our robotics operations by acquiring additional ROVs and trenchers as well as taking delivery of a newbuild chartered ROV support vessel, the Grand Canyon. In 2013, we entered into charter agreements for two similar vessels, the Grand Canyon II and the Grand Canyon III, which are expected to be delivered in 2014 and 2015, respectively. We also chartered the Rem Installer, which was delivered to us in July 2013.

Economic Outlook and Industry Influences

Demand for our services is primarily influenced by the condition of the oil and gas industry, and in particular, the willingness of oil and gas companies to make capital expenditures for offshore exploration, drilling and production operations. The performance of our business is also largely dependent on the prevailing market prices for oil and natural gas, which are impacted by global economic conditions, hydrocarbon production and capacity, geopolitical issues, weather, and several other factors, including but not limited to:

- worldwide economic activity, including available access to global capital and capital markets;
- demand for oil and natural gas, especially in the United States, Europe, China and India;
- economic and political conditions in the Middle East and other oil-producing regions;
- the effect of regulations on offshore Gulf of Mexico oil and gas operations;
- actions taken by OPEC;
- the availability and discovery rate of new oil and natural gas reserves in offshore areas;
- the exploration and production of shale oil and natural gas;
- the cost of offshore exploration for and production and transportation of oil and gas;
- the ability of oil and natural gas companies to generate funds or otherwise obtain external capital for exploration, development and production operations;
- the sale and expiration dates of offshore leases in the United States and overseas;
- technological advances affecting energy exploration production transportation and consumption;
- weather conditions;
- environmental and other governmental regulations; and
- domestic and international tax policies.

We have experienced slow but steady global economic growth during 2013. This global economic growth has been periodically interrupted with periods of strong volatility that tend to disrupt the global markets for a short duration before the markets and global economies resume their collective general slow upward trend. In the fourth quarter of 2013, some of these market disruptions included the U.S. Federal Reserve's announcement of the tapering of its multi-year "quantitative easing" program and more recently the disruptions in certain emerging market nations and the increasing concerns over the liquidity situation of the banking system within China. The economic news out of Europe has been mostly positive and its economic growth outlook appears to be growing slightly faster than previously reported. Any news suggesting weak or declining economic data could affect the global equity and commodity markets, which could adversely affect normal business activities. The oil and natural gas industry has been adversely affected by the uncertainty of the general timing and level of the economic recovery as well as the uncertainties concerning government regulation of the industry, particularly in the United States. Over the longer term, the fundamentals for our business remain favorable as the need for continued replenishment of oil and gas production is the primary driver of demand for our services.

We believe that the long-term industry fundamentals are positive based on the following factors: (1) long-term increasing world demand for oil and natural gas emphasizing the need for continual replenishment of oil and gas production; (2) mature global production rates for offshore and subsea wells; (3) globalization of the natural gas market; (4) an increasing number of mature and small reservoirs; (5) increasing offshore activity, particularly in deepwater; and (6) an increasing number of subsea developments.

Table of Contents

At December 31, 2013, we had cash on hand of $478.2 million and $584.2 million available for borrowing under our Revolving Credit Facility. Our capital expenditures for 2014 are expected to total approximately $400 million. If we successfully implement our business plan, we believe we have sufficient liquidity without incurring additional indebtedness beyond the existing capacity under the Revolving Credit Facility.

Business Activity Summary

During the four year period between 2009 and 2012, we enhanced our financial position via the generation of approximately $615 million in pre-tax proceeds primarily from dispositions of non-core business assets in order to strategically grow our core businesses. These dispositions include approximately $55 million from the sale of individual oil and gas properties, over $500 million from the sale of our stockholdings in Cal Dive and $25 million from the sale of our former reservoir consulting business.

In October 2012, we entered into an agreement to sell our two remaining pipelay vessels, the Caesar and the Express, and other related pipelay equipment for $238.3 million. In June 2013, we completed the sale of the Caesar and related equipment for $138.3 million, which amount included $30 million of funds deposited with us at the time the agreement was entered into by the parties. We used $80.1 million of the proceeds from the sale of the Caesar to reduce our indebtedness under our former credit agreement and we are investing the remainder in our continuing operations, including supporting the growth of our well intervention and robotics operations. In July 2013, we completed the sale of the Express for $100 million, including the remaining $20 million of previously deposited funds. In February 2013, we sold ERT for $624 million plus additional consideration in the form of overriding royalty interests in ERT’s Wang well and certain exploration prospects. In January 2014, we closed the sale of our spoolbase property located in Ingleside, Texas for $45 million to the same group of companies that acquired the Caesar and the Express. In connection with this sale, we received $15 million in cash and hold a $30 million promissory note, in which a $10 million principal reduction in the note’s balance is required to be paid to us on each December 31 in 2014, 2015 and 2016. The sale of our Ingleside spoolbase is expected to result in an approximately $10.5 million gain in the first quarter of 2014.

As we focus on our well intervention and robotics operations, we conducted the following activities in 2013 to expand our services capabilities:

- we executed a contract with a shipyard in Singapore for the construction of a newbuild semisubmersible well intervention vessel, the Q7000, which is expected to be completed and placed in service in 2016;
- we took possession in April 2013 of the chartered Skandi Constructor, which joined our North Sea well intervention fleet in September 2013;
- we chartered the Rem Installer effective July 2013;
- we substantially completed the conversion of the Helix 534 into a well intervention vessel in 2013 and the vessel commenced well intervention operations in the Gulf of Mexico in February 2014; and
- we entered into charter agreements for two newbuild ROV support vessels, the Grand Canyon II and the Grand Canyon III., which are expected to be delivered to us in 2014 and 2015, respectively.

RESULTS OF OPERATIONS

Historically, our well intervention, robotics, subsea construction and production facilities operations were reported as two segments: Contracting Services and Production Facilities. Following the completion of the sale of our two remaining subsea construction pipelay vessels in 2013 (Note 2) and the continued emphasis on growing our well intervention and robotics businesses, we disaggregated our former Contracting Services segment into three reportable segments: Well Intervention, Robotics and Subsea Construction. Our Subsea Construction activities are now significantly diminished following the sale of substantially all of our remaining assets related to this reportable segment. Production Facilities remains a business segment. Previously, we had an additional business segment, Oil and Gas. In December 2012, we announced a definitive agreement for the sale of ERT. The sale occurred on February 6, 2013. Accordingly, the results of ERT are presented as discontinued operations for all periods presented in this Annual Report.

All material intercompany transactions between the segments have been eliminated in our consolidated financial statements, including our consolidated results of operations.

Table of Contents

Continuing Operations

We seek to provide services and methodologies that we believe are critical to developing offshore reservoirs and maximizing production economics. Our services include Well Intervention, Robotics and Subsea Construction (see "Business Activity Summary" above regarding the dispositions of our remaining subsea construction vessels). Our businesses operate primarily in deepwater in the Gulf of Mexico, North Sea, Asia Pacific and West Africa regions, with services that cover the lifecycle of an offshore oil or gas field. In addition, our robotics operations are often contracted for the development of renewable energy projects (wind farms). As of December 31, 2013, our services had backlog of $2.0 billion, including $846.0 million expected to be performed in 2014. Our backlog includes a five-year contract with BP to provide well intervention services with our Q5000 semi-submersible vessel once its construction is completed (expected in 2015). Our Production Facilities segment reflects the results associated with the operations of the HP I as well as our equity investments in two Gulf of Mexico production facilities (Note 5). Backlog for the HP I totaled approximately $160.9 million at December 31, 2013. In connection with the sale of ERT, a revised fee arrangement for usage of the HP I at the Phoenix field was agreed upon with the acquirer of ERT. Under the terms of this arrangement, ERT pays us a lower fixed annual demand fee; however, ERT also pays us a variable throughput fee. We anticipate that the total combined fees will approximate at least the previous fixed annual demand fee over the life of the contract. Currently, the fees that we are receiving exceed the previous fixed annual demand fee. The revised terms also provide that the HP I will continue to provide service to ERT's Phoenix field through at least December 31, 2016. At December 31, 2012, the total backlog associated with our continuing operations was $829.6 million. Backlog contracts are cancelable without penalty in many cases. Backlog is not necessarily a reliable indicator of total annual revenue for our services as contracts may be added, cancelled and in many cases modified while in progress.

Discontinued Operations

In February 2013, we sold ERT for $624 million plus additional consideration in the form of overriding royalty interests in ERT's Wang well and certain exploration prospects. As a result, we have presented the assets and liabilities included in the sale of ERT and the historical operating results of our former Oil and Gas segment as discontinued operations in the accompanying consolidated financial statements (Notes 1 and 3).

Comparison of Years Ended December 31, 2013 and 2012

The following table details various financial and operational highlights for the periods presented (dollars in thousands):

	Year Ended December 31, 2013	Year Ended December 31, 2012	Increase/ (Decrease)
Revenues —			
Well Intervention	$452,452	$378,546	$73,906
Robotics	333,246	328,726	4,520
Subsea Construction	71,321	192,521	(121,200)
Production Facilities	88,149	80,091	8,058
Intercompany elimination	(68,607)	(133,775)	65,168
	$876,561	$846,109	$30,452
Gross profit —			
Well Intervention	$142,762	$100,656	$42,106
Robotics	57,035	66,005	(8,970)

Subsea Construction	18,302	(130,139)	148,441
Production Facilities	50,619	40,645	9,974
Corporate and other	(4,673)	(19,374)	14,701
Intercompany elimination	(3,360)	(7,878)	4,518
	$260,685	$49,915	$210,770

Table of Contents

	Year Ended December 31, 2013		2012	
Gross Margin —				
Well Intervention	32	%	27	%
Robotics	17	%	20	%
Subsea Construction	26	%	(68	)%
Production Facilities	57	%	51	%
Total company	30	%	6	%
Number of vessels (1) / Utilization (2)				
Contracting Services:				
Well Intervention vessels	4/92	%	3/82	%
ROVs	57/63	%	55/67	%
Robotics vessels	5/88	%	4/92	%
Subsea Construction vessels	0/92	%	2/84	%

(1) Represents number of vessels as of the end of the period excluding acquired vessels prior to their in-service dates, vessels taken out of service prior to their disposition and vessels jointly owned with a third party.

(2) Average vessel utilization rate is calculated by dividing the total number of days the vessels in this category generated revenues by the total number of calendar days in the applicable period. Utilization statistics for construction vessels only include the time each vessel was in service prior to its eventual sale.

Intercompany segment revenues during the years ended December 31, 2013 and 2012 are as follows (in thousands):

	Year Ended December 31, 2013	2012	Increase/ (Decrease)
Well Intervention	$22,448	$36,781	$(14,333)
Robotics	41,169	46,465	(5,296)
Subsea Construction	317	4,472	(4,155)
Production Facilities	4,673	46,057	(41,384)
	$68,607	$133,775	$(65,168)

Intercompany segment profit during the years ended December 31, 2013 and 2012 is as follows (in thousands):

	Year Ended December 31, 2013	2012	Increase/ (Decrease)
Well Intervention	$(141)	$6,203	$(6,344)
Robotics	3,518	180	3,338
Subsea Construction	158	1,670	(1,512)
Production Facilities	(175)	(175)	—
	$3,360	$7,878	$(4,518)

In reviewing the discussion below of our results of operations, please refer to the tables above and Note 14 for supplemental information regarding our business segment results. This discussion specifically refers to our Well Intervention, Robotics, Subsea Construction and Production Facilities segments. We recently sold our remaining Subsea Construction vessels and related equipment (Note 2). Information regarding our former Oil and Gas segment is presented under “Discontinued Operations — Oil and Gas” below and in Note 3.

Table of Contents

Revenues. Our revenues increased by 4% in 2013 as compared to 2012 reflecting year-over-year revenue increases in each of our Well Intervention, Robotics and Production Facilities segments offset in part by the substantial decrease in our Subsea Construction revenues as a result of the sale of our two remaining subsea construction pipelay vessels in mid-2013 (Note 2).

Our Well Intervention revenues increased by 20% in 2013 as compared to 2012 primarily reflecting the addition of a chartered vessel, the Skandi Constructor, to our North Sea fleet and increased utilization of our three other well intervention vessels. The higher utilization rates in 2013 primarily reflect fewer idle days associated with regulatory dry docks in 2013 (the Well Enhancer for 24 days) as compared to 2012 (the Q4000 for 70 days, the Seawell for 52 days and the Well Enhancer for 52 days). In December 2013, the Well Enhancer commenced an additional regulatory dry dock, which has been completed and the vessel returned to service in late January 2014. Our well intervention vessels have a relatively full schedule of backlog work in 2014. The Seawell and the Skandi Constructor are both expected to go into dry dock in December 2014.

Our Robotics revenues increased by 1% in 2013 as compared to 2012 primarily reflecting the greater number of ROVs owned and higher ROVDrill revenues. However, Robotics revenues were adversely affected by a decrease in the number of spot vessel opportunities in 2013 as compared to those in 2012, a reduction in utilization rates resulting from greater than usual seasonal declines in the North Sea in early 2013 and lower year-over-year trenching activities associated with the deferral of many previously anticipated 2013 trenching projects in the North Sea region to 2014 and beyond. Although trenching revenues were disappointing in 2013, we are beginning to contract such work in our 2014 schedule.

Our Subsea Construction revenues decreased by 63% in 2013 as compared to 2012 reflecting the sale of both the Caesar and the Express in mid-2013.

Our Production Facilities revenues increased by 10% in 2013 as compared to 2012, which reflects a substantial increase in our total revenues under the fee arrangement with ERT for the use of the HP I to process production from the Phoenix field, which was revised following our sale of ERT to a third party in February 2013. Revenues generated by the HP I were eliminated in consolidation prior to the sale of ERT. The quarterly HFRS retainer fee also increased effective April 1, 2013 as a result of a new set of four-year agreements.

Gross Profit. Our gross profit increased significantly in 2013 as compared to 2012. In 2012, we recorded asset impairment charges of $177.1 million, including $157.8 million for the Caesar and related mobile pipelay equipment, $14.6 million for the Intrepid, and $4.6 million for well intervention assets associated with our former operations in Australia (Note 2). Absent the effect of the related impairment charges, our gross profit increased by 15% in 2013 as compared to 2012.

Our Well Intervention gross profit increased by 42% in 2013 as compared to 2012 primarily reflecting revenue increases as a result of the addition of the Skandi Constructor and improved utilization rates in 2013.

Our Robotics gross profit decreased by 14% in 2013 as compared to 2012 reflecting the performance of a high volume of lower gross margin work in an effort to reduce the idle time of our robotics assets. The increased pressure of this business reflected a tight market in the North Sea region in early 2013 and a light trenching market throughout 2013 following a good year of such activity in 2012. As noted previously, we are now beginning to contract trenching work for 2014 and thus we believe that such activity for 2014 will be more closely correlated with 2012 than the lower levels we achieved in 2013.

The increase in Subsea Construction gross profit in 2013 as compared to 2012 primarily reflects the $172.4 million of impairment charges we recorded in 2012, offset in part by our pipelay vessels only being in operation for the first half of 2013 prior to their sale as compared to a full year of operations in 2012.

Our Production Facilities gross profit increased by 25% in 2013 as compared to 2012. The positive variance reflects both the increased processing fees under the revised contract with ERT following the completion of its sale in February 2013, and the higher retainer fee for the HFRS agreements which went into effect in April 2013.

Loss on Commodity Derivative Contracts. In December 2012, following the announcement of the sale of ERT, we de-designated our oil and gas commodity derivative contracts and interest rate swap contracts as hedging instruments (Note 16). The $14.1 million loss on commodity derivative contracts in

Table of Contents

2013 reflects the net loss on our oil and gas commodity derivative contracts during the first quarter of 2013. In February 2013, we paid approximately $22.5 million to settle our remaining open commodity derivative contracts. The $10.5 million loss on commodity derivative contracts in 2012 reflects the amount of mark-to-market loss of unsettled oil and gas commodity derivative contracts associated with de-designation of these contracts as hedging instruments.

Gain (Loss) on Sale of Assets, Net. The $14.7 million net gain on sale of assets for 2013 primarily reflects a $1.1 million loss on the sale of the Caesar in June 2013 and a $15.6 million gain on the sale of the Express in July 2013 (Note 2). The $13.5 million loss on the disposition of assets in 2012 reflects the sale of the Intrepid in September 2012.

Selling, General and Administrative Expenses. Our selling, general and administrative expenses decreased by $12.2 million in 2013 as compared to 2012. The decrease reflects the reduction in the size of our organization following the sales of ERT, the Caesar and the Express, and the related effect of these transactions on the level of our corporate staffing. This decrease in our selling, general and administrative expenses was partially offset by severance related costs of approximately $1.9 million and a $2.2 million increase in our allowance for uncollectible accounts in 2013 (Note 15). Additionally, the 2012 amount includes approximately $3.5 million of severance and other closure costs associated with our decision to sell our remaining pipelay assets, to cease our Australian well intervention operations and to terminate the remaining lease term and other related closure costs associated with our former office in Rotterdam, The Netherlands. Lastly, our 2012 amount also includes $2.6 million drawn against a letter of credit related to an international well abandonment project that was completed in 2011. We are seeking return of this amount but collection is not reasonably assured.

Equity in Earnings of Investments. Equity in earnings of investments decreased by $5.5 million in 2013 as compared to 2012. The decrease was primarily due to Independence Hub receiving lower fees from major customers of the facility following the expiration of a five-year supplemental monthly demand fee in March 2012 and lower throughput at both the Deepwater Gateway and Independence Hub facilities.

Net Interest Expense. Our net interest expense totaled $32.9 million in 2013 as compared to $48.2 million in 2012. The decrease consists of both a reduction in interest expense and increases in capitalized interest and interest income. The decrease in interest expense reflects the substantial reduction in our indebtedness, including the $318.4 million repayment of debt in February 2013 following the sale of ERT, the early redemption of $200 million of our Senior Unsecured Notes in March 2012 and our redemption in July 2013 of the remaining $275 million of the Senior Unsecured Notes then outstanding. Capitalized interest totaled $10.4 million for 2013 as compared to $4.9 million for 2012. Generally, our capitalized interest will be increasing as the construction of our vessels and related equipment progresses. Interest income totaled $1.2 million for 2013 as compared to $0.5 million for 2012, reflecting our increased average cash on hand during 2013.

Loss on Early Extinguishment of Long-term Debt. The $12.1 million loss in 2013 includes the $8.6 million loss on our redemption in July 2013 of the remaining $275 million Senior Unsecured Notes outstanding and the acceleration of the remaining deferred financing fees related to the term loan component of our former credit agreement following the repayment of indebtedness and the related termination of the facility. The charges of $17.1 million in 2012 were associated with the early extinguishment of portions of our debt, including $11.5 million related to our redemption of $200 million of our Senior Unsecured Notes and $5.6 million related to our repurchase of $142.2 million of our 2025 Notes. See Note 7 for information regarding our debt repayments.

Other Income – Oil and Gas. The $6.6 million income for 2013 represents the proceeds associated with our overriding royalty interests in ERT's Wang well, which commenced production in late April 2013, and cash payments related to services we provided to ERT following its sale.

Income Tax Provision (Benefit). Income taxes reflected an expense of $31.6 million in 2013 as compared to a benefit of $59.2 million in 2012. The variance primarily reflects increased profitability in the current year period. The effective tax rate for 2013 was a 22% expense. The effective tax rate for 2012 was a 47% benefit. The variance is primarily attributable to increased profitability of operations located within the United States.

Table of Contents

Comparison of Years Ended December 31, 2012 and 2011

The following table details various financial and operational highlights for the periods presented (dollars in thousands):

	Year Ended December 31,		Increase/
	2012	2011	(Decrease)
Revenues —			
Well Intervention	$378,546	$340,952	$37,594
Robotics	328,726	245,360	83,366
Subsea Construction	192,521	151,923	40,598
Production Facilities	80,091	75,460	4,631
Intercompany elimination	(133,775)	(111,695)	(22,080)
	$846,109	$702,000	$144,109
Gross profit —			
Well Intervention	$100,656	$97,065	$3,591
Robotics	66,005	45,279	20,726
Subsea Construction	(130,139)	(4,900)	(125,239)
Production Facilities	40,645	39,170	1,475
Corporate and other	(19,374)	(27,024)	7,650
Intercompany elimination	(7,878)	93	(7,971)
	$49,915	$149,683	$(99,768)
Gross Margin —			
Well Intervention	27%	28%	
Robotics	20%	18%	
Subsea Construction	(68)%	(3)%	
Production Facilities	51%	52%	
Total company	6%	21%	
Number of vessels (1) / Utilization (2)			
Contracting Services:			
Well intervention	3/82%	3/90%	
ROVs	55/67%	46/60%	
Robotics vessels	4/92%	5/92%	
Subsea Construction vessels	2/84%	3/54%	

(1) Represents number of vessels as of the end of the period excluding acquired vessels prior to their in-service dates, vessels taken out of service prior to their disposition and vessels jointly owned with a third party.

(2) Average vessel utilization rate is calculated by dividing the total number of days the vessels in this category generated revenues by the total number of calendar days in the applicable period. Utilization statistics for construction vessels only include the time each vessel was in service prior to its eventual sale.

Intercompany segment revenues during the years ended December 31, 2012 and 2011 are as follows (in thousands):

	Year Ended December 31,		Increase/
	2012	2011	(Decrease)

Well Intervention	$36,781	$16,175	$20,606
Robotics	46,465	45,251	1,214
Subsea Construction	4,472	4,212	260
Production Facilities	46,057	46,057	—
	$133,775	$111,695	$22,080

Table of Contents

Intercompany segment profit during the years ended December 31, 2012 and 2011 are as follows (in thousands):

	Year Ended December 31, 2012	2011	Increase/ (Decrease)
Well Intervention	$6,203	$(223)	$6,426
Robotics	180	213	(33)
Subsea Construction	1,670	114	1,556
Production Facilities	(175)	(197)	22
	$7,878	$(93)	$7,971

Revenues. Our revenues increased by 21% in 2012 as compared to 2011 primarily reflecting increased utilization of our Robotics assets and significantly higher utilization for our subsea construction vessels.

Our Well Intervention revenues increased by 11% in 2012 as compared to 2011 despite the reduction in our vessels collective utilization rate in 2012. The decrease in the utilization rate reflects all three of our then existing well intervention vessels being in regulatory dry dock for portions of 2012 (the Q4000 for 70 days, the Seawell for 52 days and the Well Enhancer for 52 days). The lost days associated with the regulatory dry docks were more than offset by increased rates reflecting high demand for our well intervention services and vessels.

Our Robotics revenues increased by 34% in 2012 as compared to 2011 reflecting high utilization of our chartered vessels and owned ROVs, the utilization of a number of additional spot market vessels for much of 2012, and the performance of a number of North Sea trenching projects in early 2012 (which activities are not normally conducted during the first quarter in large part because of seasonal weather patterns).

Our Subsea Construction revenues increased by 27% in 2012 as compared to 2011. Our revenues benefited from an increase in activity in the Gulf of Mexico in the first quarter of 2012, full year deployment of the Caesar on an accommodation project in Mexico which commenced in the fourth quarter of 2011, and the Express working offshore Israel and in the North Sea for most of the second and third quarters of 2012.

Our Production Facilities revenues increased by 6% in 2012 as compared to 2011, which primarily reflects the inclusion of the quarterly HFRS retainer fee, which commenced on April 1, 2011.

Gross Profit. Our gross profit decreased by 67% in 2012 as compared to 2011. This decrease was primarily attributed to asset impairment charges of $157.8 million for the Caesar and related mobile pipelay equipment, $14.6 million for the Intrepid, and $4.6 million for well intervention assets associated with our former operations in Australia (Note 2). Excluding the aforementioned impairment charges, our gross profit increased by 52% in 2012 as compared to 2011 reflecting the increased activity in all of our business segments.

As discussed in “revenues” above, our Well Intervention business was negatively impacted in 2012 because of the lost utilization of our Q4000, Seawell and Well Enhancer well intervention vessels as a result of extended regulatory dry docks. In 2012, our Well Intervention revenues benefitted from the rental of additional well intervention equipment to third parties.

Our Robotics gross profit increased by 46% in 2012 as compared to 2011 reflecting increased utilization of its then existing asset base thereby reducing idle costs, and the use of spot vessels for much of 2012.

Excluding the effect of the $172.4 million of impairment charges associated with its pipelay vessels and related equipment, Subsea Construction gross profit increased $47.1 million as compared to 2011. The increase primarily reflects the high margins achieved on many of our subsea projects in 2012, more specifically with respect to a very successful project located offshore Israel.

Loss on Commodity Derivative Contracts. The $10.5 million loss on commodity derivative contracts primarily reflects the amount of mark-to-market loss on unsettled oil and gas commodity derivative contracts associated with de-designation of these contracts as hedging instruments following the announcement in December 2012 of the sale of ERT.

Loss on Sale of Assets, Net. The $13.5 million loss on the disposition of assets in 2012 reflects the sale of the Intrepid in September 2012 (Note 2).

Selling, General and Administrative Expenses. Our selling, general and administrative expenses increased by $7.8 million in 2012 as compared to 2011. The increase was associated with higher long-term incentive compensation, which primarily reflects the fact that amortization of awards granted in 2012 vest over a period of three years (as compared to a five-year vesting period for all long-term incentive awards granted prior to 2012) (Note 9). Additionally, the 2012 amount includes approximately $3.5 million of severance and other closure costs associated with our decision to sell our remaining pipelay assets, to cease our Australian well intervention operations and to terminate the remaining lease term and other related closure costs associated with a former office located in Rotterdam, the Netherlands. Lastly, our 2012 amount also includes $2.6 million drawn against a letter of credit related to an international well abandonment project which was completed in 2011. We are seeking return of this amount but collection is not reasonably assured. Our selling, general and administrative expenses in 2011 include $1.6 million of severance costs related to the resignation of our former Executive Vice President and Chief Operating Officer.

As a percentage of revenues, our selling, general and administrative expenses were higher than our previously-reported amounts due to previously-allocated corporate shared services costs related to ERT being included in the results of our continuing operations. Under the applicable accounting guidance, such allocations are not permitted to be excluded from our selling, general and administrative expenses when a former business is presented as discontinued operations. The amount of corporate shared services that were previously allocated to ERT totaled $14.9 million in 2012 and $18.5 million in 2011.

Equity in Earnings of Investments. Equity in earnings of investments decreased by $13.8 million in 2012 as compared to 2011. The decrease was primarily due to Independence Hub receiving lower fees from major customers of the facility following the expiration of a five-year supplemental monthly demand fee in March 2012, as well as lower throughput at both the Deepwater Gateway and Independence Hub facilities reflecting both storm-related disruptions and normal production declines of the fields using the facilities.

Net Interest Expense. Our net interest expense totaled $48.2 million in 2012 as compared to $70.2 million in 2011. The decrease in interest expense primarily reflects a $275 million reduction of our Senior Unsecured Notes indebtedness, including the early extinguishment of $75 million in the third quarter of 2011 and $200 million in the first quarter of 2012. The Senior Unsecured Notes bore a 9.5% interest rate which was greater than the 5.4% weighted average interest rate of our total indebtedness as of December 31, 2012. Capitalized interest totaled $4.9 million in 2012 as compared to $1.3 million in 2011. Interest income totaled $0.5 million in 2012 as compared with $1.4 million in 2011.

Loss on Early Extinguishment of Long-term Debt. The charges of $17.1 million in 2012 were associated with the early extinguishment of portions of our debt in the first quarter of 2012, including $11.5 million related to our redemption of $200 million of our Senior Unsecured Notes and $5.6 million related to our repurchase of $142.2 million of our 2025 Notes (Note 7). The $2.4 million amount in 2011 was related to premiums we paid to repurchase approximately $75 million of our Senior Unsecured Notes during the third quarter of 2011.

Other Expense, Net. We reported net other expenses of $0.7 million in 2012 as compared to $1.1 million in 2011. These amounts primarily reflect foreign exchange fluctuations in our non-U.S. dollar functional currencies. We recorded foreign exchange losses of approximately $0.1 million in 2012 as compared to $1.9 million in 2011. The foreign exchange losses were attributed to the strengthening of the U.S. dollar against other global currencies. Included in these foreign exchange gains or losses were $0.4 million and $0.2 million of gains related to our foreign exchange contracts in 2012 and 2011, respectively (Note 16). In 2012, we recorded a $0.6 million loss associated with the de-designation of our interest rate swaps. In 2011, we sold our remaining 0.5 million shares of Cal Dive common stock for net proceeds of approximately $3.6 million. Our gain on this sale of the remaining Cal Dive common shares was approximately $0.8 million.

Table of Contents

Income Tax Benefit. Income taxes reflected a benefit of $59.2 million in 2012 as compared to $36.8 million in 2011. The variance primarily reflects decreased profitability in 2012 as compared to 2011. The effective tax rate of a 47% benefit for 2012 was less favorable than the effective tax rate for 2011. The favorable effective tax rate for 2011 reflects the $31.3 million net tax benefit derived from the reorganization of our Australian well intervention operations.

Discontinued Operations — Oil and Gas

All of our oil and gas assets sold in February 2013 were located in the U.S. Gulf of Mexico. The operating results of our discontinued oil and gas operations during 2013, 2012 and 2011 are presented in Note 3. Our continuing operations include one oil and gas property located offshore of the United Kingdom ("U.K."). We completed the reclamation activities of this offshore property in 2013 in accordance with the applicable U.K. regulations (Note 3). We had no revenue associated with our U.K. oil and gas property during the three-year period ended December 31, 2013. There were no operating costs associated with this U.K. property in 2013. Operating costs for 2012 and 2011 totaled $0.7 million and $4.0 million, respectively.

LIQUIDITY AND CAPITAL RESOURCES

Overview

The following table presents certain information useful in the analysis of our financial condition and liquidity as of December 31, 2013 and 2012 (in thousands):

	2013	2012
Net working capital	$553,427	$351,061
Long-term debt (1)	$545,776	$1,002,621
Liquidity (2)	$1,062,413	$924,688

(1) Long-term debt does not include the current maturities portion of the long-term debt as that amount is included in net working capital. It is also net of unamortized debt discount on the 2032 Notes. We repaid $318.4 million of our outstanding indebtedness in February 2013 following the sale of ERT, and $150.4 million in June 2013 with proceeds from the sale of the Caesar and cash generated from operations (see table below). See Note 7 for information related to our existing debt.

(2) Liquidity, as defined by us, is equal to cash and cash equivalents plus available capacity under our Revolving Credit Facility, which capacity is reduced by current letters of credit drawn against the facility. Our liquidity at December 31, 2013 includes cash and cash equivalents of $478.2 million and $584.2 million of available borrowing capacity under our Revolving Credit Facility (Note 7). Our liquidity at December 31, 2012 includes cash and cash equivalents of $437.1 million and $487.6 million of available borrowing capacity under our former revolving credit facility. The increase in our liquidity reflects proceeds from the sales of ERT, the Caesar and the Express.

The carrying amount of our debt, including current maturities, as of December 31, 2013 and 2012 is as follows (in thousands):

	2013	2012
Term Loans (mature July 2015) (1)	$—	$367,181

Revolving Credit Facility (matures July 2015) (1)	—	100,000
Term Loan (matures June 2018)	292,500	—
2025 Notes (mature December 2025) (2)	—	3,487
2032 Notes (mature March 2032) (3)	173,484	168,312
Senior Unsecured Notes (mature January 2016) (4)	—	274,960
MARAD Debt (matures February 2027)	100,168	105,288
Total debt	$566,152	$1,019,228

Table of Contents

(1) In February 2013, we repaid $293.9 million of our former term loan debt and $24.5 million under our former revolving credit facility with the proceeds from the sale of ERT. In June 2013, we used $150.4 million of the proceeds from the sale of the Caesar as well as cash generated from operations to repay the remaining amounts outstanding under our former credit agreement (Note 7).

(2) This amount represents the remaining 2025 Notes that we repurchased in February 2013 (Note 7).

(3) These amounts are net of the unamortized debt discount of $26.5 million and $31.7 million, respectively. The notes will increase to the $200 million face amount through accretion of non-cash interest charges through March 15, 2018, which is the date on which the holders of the notes may first require us to repurchase the notes.

(4) In July 2013, we redeemed the remaining Senior Unsecured Notes.

The following table provides summary data from our consolidated statements of cash flows (in thousands):

	Year Ended December 31,		
	2013	2012	2011
Cash provided by (used in):			
Operating activities	$104,861	$176,068	$182,657
Investing activities	$(126,077)	$(295,712)	$(95,300)
Financing activities	$(487,421)	$(145,232)	$(229,895)
Discontinued operations (1)	$552,462	$156,373	$297,481

(1) Represents total cash flows associated with the operations of ERT. ERT was sold in February 2013. Proceeds from the sale of ERT totaled $614.8 million, net of transaction costs. Other cash flows in the table above reflect our continuing operations.

Our current requirements for cash primarily reflect the need to fund capital expenditures to allow the growth of our current lines of business and to service our existing debt. We may also repay debt with any additional free cash flow from operations. Historically, we have funded our capital program, including acquisitions, with cash flows from operations, borrowings under credit facilities and use of project financing along with other debt and equity alternatives.

We remain focused on maintaining a strong balance sheet and adequate liquidity. We have a reasonable basis for estimating our future cash flows supported by our existing and expanding backlog. We believe that internally generated cash flows and available borrowing capacity under our Revolving Credit Facility will be sufficient to fund our operations over at least the next twelve months.

In accordance with our Credit Agreement, 2032 Notes and MARAD debt, we are required to comply with certain covenants and restrictions, including certain financial ratios such as a consolidated interest coverage ratio and consolidated leverage ratio, as well as the maintenance of minimum net worth, working capital and debt-to-equity requirements. Our Credit Agreement also contains provisions that limit our ability to incur certain types of additional indebtedness. These provisions effectively prohibit us from incurring any additional secured indebtedness or indebtedness guaranteed by us. The Credit Agreement does permit us to incur certain unsecured indebtedness, and also provides for our subsidiaries to incur project financing indebtedness (such as our MARAD loan) secured by the underlying asset, provided that such indebtedness is not guaranteed by us. The Credit Agreement also permits our Unrestricted Subsidiaries to incur indebtedness provided that it is not guaranteed by us or any of our Restricted Subsidiaries. As of December 31, 2013 and 2012, we were in compliance with all of our then existing debt covenants and restrictions.

A prolonged period of weak economic activity may make it difficult to comply with our covenants and other restrictions in agreements governing our debt. Our ability to comply with these covenants and other restrictions is affected by economic conditions and other events beyond our control. If we fail to comply with these covenants and other restrictions, such failure could lead to an event of default, the possible acceleration of our repayment of outstanding debt and the exercise of certain remedies by the lenders, including foreclosure against our collateral.

Table of Contents

Under the terms of our Credit Agreement, in July 2013 we borrowed $300 million under our term loan in connection with our early redemption of the remaining $275 million Senior Unsecured Notes then outstanding. We may borrow up to $600 million under our revolving credit facility. The revolving credit facility also permits us to obtain letters of credit up to the full amount of this credit facility. Subject to customary conditions, we may request that aggregate commitments with respect to the revolving credit facility be increased by, or additional term loans be made of, or a combination thereof, up to $200 million. See Note 7 for additional information relating to our long-term debt, including more information regarding our current and former credit agreements, including covenants and collateral.

The 2032 Notes can be converted prior to their stated maturity upon certain triggering events specified in the Indenture governing the notes. Beginning in March 15, 2018, the holders of the 2032 Notes may require us to repurchase these notes or we may at our own option elect to repurchase them. To the extent we do not have cash on hand or long-term financing secured to cover the conversion, the 2032 Notes would be classified as current liabilities in our consolidated balance sheet. No conversion triggers were met during the years ended December 31, 2013 and 2012. Our 2025 Notes were extinguished when the holders exercised their option for us to repurchase their notes in December 2012 ($154.3 million) and in February 2013 when we repurchased the remaining $3.5 million of the 2025 Notes that were not put to us by the holders in December 2012.

Operating Cash Flows

Total cash flows from operating activities decreased by $378.1 million in 2013 as compared to 2012 primarily reflecting the sales of ERT and our remaining pipelay vessels, payment of taxes associated with the sales, and the related settlement of our commodity derivatives.

Total cash flows from operating activities decreased by $114.7 million in 2012 as compared to 2011 primarily reflecting decreased oil and natural gas production, a substantial increase in costs incurred in performing oil and gas asset retirement projects and the effect of some of our vessels being in extended regulatory dry dock in 2012. These decreases were partially offset by an increased level of contracting services activity and the higher oil prices realized during 2012.

Investing Activities

Capital expenditures have consisted principally of the purchase or construction of dynamically positioned vessels; improvements and modifications to existing assets; acquisition, exploration and development of oil and gas properties; and investments in our production facilities. Significant sources (uses) of cash associated with investing activities for the years ended December 31, 2013, 2012 and 2011 are as follows (in thousands):

	Year Ended December 31,		
	2013	2012	2011
Capital expenditures:			
Well Intervention	$(283,132)	$(274,451)	$(13,923)
Robotics	(39,655)	(44,500)	(27,045)
Production Facilities	(1,252)	(823)	(30,896)
Other	(387)	(3,265)	(28,290)
Distributions from equity investments, net (1)	9,295	7,797	1,266
Proceeds from sale of assets (2)	189,054	19,530	3,588
Net cash used in investing activities – continuing operations	(126,077)	(295,712)	(95,300)
Oil and Gas capital expenditures	(31,855)	(125,423)	(119,615)
Proceeds from sale of ERT, net of transaction costs	614,820	—	—
Proceeds from sale of assets	—	—	31,000

Other	—	5,366	1,598
Net cash provided by (used in) investing activities – discontinued operations	582,965	(120,057)	(87,017)
Net cash provided by (used in) investing activities	$456,888	$(415,769)	$(182,317)

Table of Contents

(1) Distributions from equity investments are net of undistributed equity earnings from our equity investments. Gross distributions from our equity investments for the years ended December 31, 2013, 2012 and 2011 were $12.3 million, $16.2 million and $26.2 million, respectively (Note 5).

(2) Proceeds from sale of assets primarily reflect cash received from the sale of both the Caesar and the Express in mid-2013 and the sales of the Intrepid and certain equipment associated with our former Australian well intervention operations in 2012.

Capital expenditures associated with our business primarily include the payments associated with the construction of the Q5000 and the Q7000 (see below), payments in connection with the acquisition and subsequent upgrades and modifications of the Helix 534 (see below), and the costs incurred in the construction of additional ROVs and trenchers related to our robotics operations.

In March 2012, we executed a contract with a shipyard in Singapore for the construction of a newbuild semisubmersible well intervention vessel, the Q5000. This $386.5 million shipyard contract represents the majority of the expected costs associated with the construction of the Q5000. Pursuant to the terms of this contract, payments are made in a fixed percentage of the contract price, together with any variations, on contractually scheduled dates. At December 31, 2013, our total investment in the Q5000 was $210.6 million, including $173.8 million of scheduled payments made to the shipyard. We plan to spend approximately $146 million on the Q5000 in 2014, including scheduled shipyard payments of $115.9 million. The vessel is expected to be completed and placed in service in 2015.

In August 2012, we acquired the Discoverer 534 drillship from a subsidiary of Transocean Ltd. for $85 million. The vessel, renamed the Helix 534, underwent upgrades and modifications to render it suitable for use as a well intervention vessel and commenced well intervention operations in the Gulf of Mexico in February 2014. At December 31, 2013, our investment in the acquisition and subsequent upgrades and modifications of the Helix 534 totaled $202.8 million, including related well control equipment.

In April 2013, we chartered the Skandi Constructor and incurred approximately $45.2 million to fully equip the vessel for use in our North Sea well operations.

In September 2013, we executed a second contract with the same shipyard in Singapore that is currently constructing the Q5000. This contract provides for the construction of a newbuild semi-submersible well intervention vessel, the Q7000, which will be built to North Sea standards. This $346.0 million shipyard contract represents the majority of the expected costs associated with the construction of the Q7000. Pursuant to the terms of this contract, 20% of the contract price was paid upon the signing of the contract and the remaining 80% will be paid upon the delivery of the vessel, which is expected to occur in 2016.
At December 31, 2013, our total investment in the Q7000 was $76.7 million, including $69.2 million paid to the shipyard upon signing the contract.

Net cash used in discontinued operations relates to capital expenditures associated with ERT. Oil and Gas capital expenditures for the first quarter of 2013 include costs associated with the exploration and development activities primarily related to the Wang well within the Phoenix field at Green Canyon Block 237.

Outlook

We anticipate that our capital expenditures in 2014 will total approximately $400 million. These estimates may increase or decrease based on various economic factors and/or existence of additional investment opportunities. However, we may reduce the level of our planned future capital expenditures given any prolonged economic downturn. We believe that our cash on hand, internally-generated cash flows, and availability under our new credit facility will provide the capital necessary to continue funding our 2014 initiatives.

Table of Contents

Contractual Obligations and Commercial Commitments

The following table summarizes our contractual cash obligations as of December 31, 2013 and the scheduled years in which the obligations are contractually due (in thousands):

	Total (1)	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
2032 Notes (2)	$200,000	$—	$—	$—	$200,000
Term Loan (3)	292,500	15,000	52,500	225,000	—
MARAD debt	100,168	5,376	11,570	12,754	70,468
Interest related to debt	204,480	23,774	44,480	33,953	102,273
Property and equipment (4)	544,074	170,658	373,416	—	—
Operating leases (5)	588,430	123,105	261,739	136,098	67,488
Total cash obligations	$1,929,652	$337,913	$743,705	$407,805	$440,229

(1) Excludes unsecured letters of credit outstanding at December 31, 2013 totaling $15.8 million. These letters of credit guaranty items such as various contractual obligations, contract bidding and insurance activities.

(2) Contractual maturity in 2032. The 2032 Notes can be converted prior to their stated maturity if the closing price of Helix's common stock for at least 20 days in the period of 30 consecutive trading days ending on the last trading day of the preceding fiscal quarter exceeds 130% of their issuance price on that 30th trading day (i.e., $32.53 per share). At December 31, 2013, the conversion trigger was not met. The first date that the holders of these notes may require us to repurchase the notes is March 15, 2018. See Note 7 for additional information.

(3) Amount reflects borrowings in July 2013. The Term Loan will mature on June 19, 2018.

(4) Primarily reflects the costs of constructing our new semi-submersible well intervention vessels, the Q5000 and the Q7000, and costs associated with the upgrades and modifications to render the Helix 534 suitable for use as a well intervention vessel.

(5) Operating leases include vessel charters and facility leases. At December 31, 2013, our vessel charter and ROV lease commitments totaled approximately $547.5 million, including two vessels that will not be delivered to us until 2014 and 2015, respectively.

Contingencies

Under terms of the equity purchase agreement for the sale of ERT, we required the buyer to provide bonding in a sufficient amount as determined by the Bureau of Ocean Energy Management ("BOEM") to cover the decommissioning costs of ERT's lease properties and thus to replace and allow for a full discharge of our existing guaranty to the BOEM for ERT's lease obligations. The buyer posted the bonding required by the equity purchase agreement, and a formal request to the BOEM for a release of our guaranty is pending.

In 2007, we were subcontracted to perform development work for a large gas field offshore India. Work commenced in the fourth quarter of 2007 and we completed our scope of work in the third quarter of 2009. We had collected approximately $303 million related to this project with an amount of uncollected trade receivables remaining. In 2010, we requested arbitration in India pursuant to the terms of the subcontract to pursue our claims and the prime contractor also requested arbitration and asserted certain counterclaims against us. Based on number of factors associated with ongoing negotiations with the prime contractor, in 2010 we reduced our trade receivable balance to an amount that we believed to be ultimately realizable. The parties have been engaged in extensive settlement discussions over time to resolve this matter outside of the arbitration process, and in December 2013 the parties reached a settlement agreement, pursuant to which we collected the receivable and the parties dropped all claims against each other.

Table of Contents

We are currently undergoing a VAT audit from the State of Andhra Pradesh, India (the "State") for the tax years 2010, 2009, 2008 and 2007 related to an Indian subsea construction and diving contract that we entered into in December 2006. We believe that we have complied with all rules and regulations as related to VAT in the State and we anticipate no additional assessments as a result of this audit.

See Item 3. Legal Proceedings and Notes 2 and 13 for additional discussion of our contingencies.

CRITICAL ACCOUNTING ESTIMATES AND POLICIES

Our results of operations and financial condition, as reflected in the accompanying consolidated financial statements and related footnotes, are prepared in conformity with accounting principles generally accepted in the United States. As such, we are required to make certain estimates, judgments and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the periods presented. We base our estimates on historical experience, available information and various other assumptions we believe to be reasonable under the circumstances. These estimates may change as new events occur, as more experience is acquired, as additional information is obtained and as our operating environment changes. We believe the most critical accounting policies in this regard are those described below. While these issues require us to make judgments that are somewhat subjective, they are generally based on a significant amount of historical data and current market data. See Note 2 for a detailed discussion on the application of our accounting policies.

Revenue Recognition

Revenues from our services are derived from contracts, which are both short-term and long-term in duration. Our long-term contracts are contracts that contain either lump-sum, turnkey provisions or provisions for specific time, material and equipment charges, which are billed in accordance with the terms of such contracts. We recognize revenue as it is earned at estimated collectible amounts. Further, we record revenues net of taxes collected from customers and remitted to governmental authorities.

Unbilled revenue represents revenue attributable to work completed prior to period end that has not yet been invoiced. All amounts included in unbilled revenue at December 31, 2013 and 2012 are expected to be billed and collected within one year. However, we also monitor the collectability of our outstanding trade receivables on a continual basis in connection with our evaluation of allowance for doubtful accounts.

Revenues generated from specific time, materials and equipment contracts are generally earned on a dayrate basis and recognized as amounts are earned in accordance with contract terms. In connection with these contracts, we may receive revenues for mobilization of equipment and personnel. Revenues related to mobilization are deferred and recognized over the period in which contracted services are performed using the straight-line method. Incremental costs incurred directly for mobilization of equipment and personnel to the contracted site, which typically consist of materials, supplies and transit costs, are also deferred and recognized over the period in which contracted services are performed using the straight-line method. Our policy to amortize the revenues and costs related to mobilization on a straight-line basis over the estimated contract service period is consistent with the general pace of activity, level of services being provided and dayrates being earned over the service period of the contract. Mobilization costs to move vessels when a contract does not exist are expensed as incurred.

Revenue on significant turnkey contracts is recognized under the percentage-of-completion method based on the ratio of costs incurred to total estimated costs at completion. Under the percentage-of-completion method, we recognize estimated contract revenue based on costs incurred to date as a percentage of total estimated costs. Changes in the expected cost of materials and labor, productivity, scheduling and other factors affect the total estimated costs. Additionally, external factors, including weather and other factors outside of our control, may also affect the progress and estimated cost of a project's completion and, therefore, the timing of income and revenue recognition. We routinely review estimates related to our contracts and reflect revisions to profitability in earnings on a current basis. If a current estimate of total contract cost indicates an ultimate loss on a contract, we recognize the projected loss in full when it is first determined. We recognize additional contract revenue related to claims when the claim is probable and legally enforceable.

Table of Contents

Goodwill and Other Intangible Assets

We are required to perform an annual impairment analysis of goodwill. We elected November 1 to be our annual impairment assessment date for goodwill. However, we could be required to evaluate the recoverability of goodwill prior to the annual assessment date if we experience disruption to the business, unexpected significant declines in operating results, divestiture of a significant component of the business, emergence of unanticipated competition, loss of key personnel or a sustained decline in market capitalization. Our goodwill impairment test involves a comparison of the fair value with our carrying amount. The fair value is determined using discounted cash flows and other market-related valuation models. At the time of our annual assessment of goodwill on November 1, 2013, we had two reporting units with goodwill.

Goodwill impairment is determined using a two-step process. The first step is to identify if a potential impairment exists by comparing the fair value of the reporting unit with its carrying amount, including goodwill. If the fair value of a reporting unit exceeds its carrying amount, goodwill of the reporting unit is not considered to have a potential impairment and the second step of the impairment test is not necessary. However, if the carrying amount of a reporting unit exceeds its fair value, the second step is performed to determine if goodwill is impaired and to measure the amount of impairment loss to recognize, if any.

The second step compares the implied fair value of goodwill with the carrying amount of goodwill. If the implied fair value of goodwill exceeds the carrying amount, then goodwill is not considered impaired. However, if the carrying amount of goodwill exceeds the implied fair value, an impairment loss is recognized in an amount equal to that excess. The implied fair value of goodwill is determined in the same manner as the amount of goodwill recognized in a business combination (i.e., the fair value of the reporting unit is allocated to all the assets and liabilities, including any unrecognized intangible assets, as if the reporting unit were acquired in a business combination).

We use both the income approach and the market approach to estimate the fair value of our reporting units under the first step of our goodwill impairment assessment. Under the income approach, a discounted cash flow analysis is performed requiring us to make various judgmental assumptions about future revenue, operating margins, growth rates and discount rates. These judgmental assumptions are based on our budgets, long-term business plans, economic projections, anticipated future cash flows and market place data. These assumptions could ultimately be materially different from our future actual results. Under the market approach, the fair value of each reporting unit is calculated by applying an average peer total invested capital EBITDA (defined as earnings before interest, income taxes and depreciation and amortization) multiple to forecasted budgeted EBITDA for each reporting unit. Judgment is required when selecting peer companies that operate in the same or similar lines of business and are potentially subject to the same economic risks.

Our goodwill at December 31, 2013, 2012 and 2011 was associated with our Well Intervention and Robotics segments. In our 2013 goodwill impairment analysis, the fair value of both of our reporting units with goodwill exceeded their respective carrying value. In addition, both reporting units have historically had strong operational performance, and absent any significant downturn in their areas of service, should be able to support their goodwill amounts for the foreseeable future. Therefore, we concluded that our goodwill at December 31, 2013 was not impaired. As a result of the adoption of an update issued by the Financial Accounting Standards Board (the “FASB”) in 2011 to simplify goodwill impairment testing, we performed qualitative assessments during 2012 and 2011 to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount including goodwill. Based on the then current and historical evidence supporting these reporting units’ carrying value being sufficient to maintain their recorded goodwill amounts, we concluded that there was no indication of goodwill impairment and forwent the quantitative step one impairment analysis. We continue to monitor the current and future operations of these two reporting units to determine whether or not the quantitative assessment is once again necessary. We conduct the quantitative test at least every three years with the latest such test occurring on

November 1, 2013.

Income Taxes

Deferred income taxes are based on the differences between the financial reporting and tax bases of assets and liabilities. We utilize the liability method of computing deferred income taxes. The liability method is based on the amount of current and future taxes payable using tax rates and laws in effect at the balance sheet date. Income taxes have been provided based upon the tax laws and rates in the countries in which operations are conducted and income is earned. A valuation allowance for deferred tax assets is recorded when it is more likely than not that some or all of the benefit from the deferred tax asset will not be realized.

We consider the undistributed earnings of our principal non-U.S. subsidiaries to be permanently reinvested. At December 31, 2013, our principal non-U.S. subsidiaries had accumulated earnings and profits of approximately $202.6 million. We have not provided deferred U.S. income tax on the accumulated earnings and profits as we consider them permanently reinvested.

It is our policy to provide for uncertain tax positions and the related interest and penalties based upon management's assessment of whether a tax benefit is more likely than not to be sustained upon examination by tax authorities. At December 31, 2013, we believe we have appropriately accounted for any unrecognized tax benefits. To the extent we prevail in matters for which a liability for an unrecognized tax benefit is established or are required to pay amounts in excess of the liability, our effective tax rate in a given financial statement period may be affected.

See Note 8 for discussion of net operating loss carry forwards, deferred income taxes and uncertain tax positions taken by us.

Derivative Instruments and Hedging Activities

Our risk management activities involve the use of derivative financial instruments to hedge the impact of market risk exposure. Historically, we have used derivative instruments to reduce our market risk exposure related to oil and gas prices (prior to the sale of ERT), variable interest rates and foreign currency exchange rates. To reduce the impact of these risks on earnings and increase the predictability of our cash flows, from time to time we have entered into certain derivative contracts, including costless collars and swaps for a portion of our oil and gas production, interest rate swaps, and foreign currency exchange contracts. All derivative contracts are reflected in our balance sheet at fair value, unless otherwise noted.

We formally document all relationships between hedging instruments and the related hedged items, as well as our risk management objectives, strategies for undertaking various hedge transactions and our methods for assessing and testing correlation and hedge ineffectiveness. All hedging instruments are linked to the hedged asset, liability, firm commitment or forecasted transaction. We also assess, both at the inception of the hedge and on an on-going basis, whether the derivatives that are used in our hedging transactions are highly effective in offsetting changes in cash flows of the hedged items. Changes in the assumptions used could impact whether the fair value change in the hedged instrument is charged to earnings or accumulated other comprehensive income (loss).

The fair value of our oil and gas derivative contracts reflected our best estimate and was based upon exchange or over-the-counter quotations whenever they are available. Quoted valuations may not have been available due to location differences or terms that extend beyond the period for which quotations are available. Where quotes were not available, we utilized other valuation techniques or models to estimate market values. The fair value of our interest rate swaps is calculated as the discounted cash flows of the difference between the rate fixed by the hedge instrument and the LIBOR forward curve over the remaining term of the hedge instrument. The fair value of our foreign currency exchange contracts is calculated as the discounted cash flows of the difference between the fixed payment as specified by the hedge instrument and the expected cash inflow of the forecasted transaction using a foreign currency forward curve.

These modeling techniques require us to make estimates of future prices, price correlation and market volatility and liquidity. Our actual results may differ from our estimates, and these differences can be positive or negative.

We engage solely in cash flow hedges. Changes in the derivative fair values that are designated as cash flow hedges are deferred to the extent that they are effective and are recorded as a component of accumulated other comprehensive income or loss (a component of shareholders' equity) until the hedged transactions occur and are recognized in earnings. The ineffective portion of a cash flow hedge's change in value is recognized immediately in earnings. In addition, any change in the fair value of a derivative that does not qualify for hedge accounting is recorded in earnings in the period in which the change occurs (Notes 2 and 16).

Table of Contents

As a result of the announcement of the sale of ERT in December 2012, we de-designated all of our then remaining oil and natural gas derivative contracts as hedging instruments. In addition, under the terms of our former credit facility (Note 7), we were required to use a portion of the proceeds from the sales of the Caesar, the Express and ERT to make payments to reduce our indebtedness. Because it was probable that we would pay off the corresponding indebtedness before the expiration of our interest rate swaps, we concluded in December 2012 that the swaps no longer qualified as cash flow hedges. In connection with the de-designation of these derivative contracts as hedging instruments, we were required to recognize amounts previously recorded in accumulated other comprehensive income (loss) and related deferred taxes into earnings. We settled all of our then remaining commodity derivative contracts and interest swap contracts in February 2013.

In January and February 2013, we entered into foreign currency exchange contracts to hedge the foreign currency exposure associated with charter payments for the Grand Canyon, the Grand Canyon II and the Grand Canyon III. These contracts currently qualify for hedge accounting treatment. All of our remaining foreign exchange contracts are not accounted for as hedge contracts and changes in their fair value are being marked-to-market in earnings in each reporting period.

In September 2013, we entered into interest rate swap contracts to fix the interest rate on $148.1 million of our Term Loan debt (Note 7). These monthly contracts also qualify for hedge accounting treatment.

See Notes 2 and 16 for additional information regarding our derivative contracts.

Property and Equipment

Property and equipment is recorded at cost. Depreciation expense is derived primarily using the straight-line method over the estimated useful lives of the assets (Note 2).

Assets used in operations are assessed for impairment whenever changes in facts and circumstances indicate a possible significant deterioration in the future cash flows expected to be generated by an asset group. If, upon review, the sum of the undiscounted pretax cash flows is less than the carrying value of the asset group, the carrying value is written down to estimated fair value and reported as an impairment charge (a component of cost of sales) in the periods in which the determination of the impairment is made. Individual assets are grouped for impairment purposes at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets. Our marine vessels are assessed on a vessel by vessel basis, while our ROVs are grouped and assessed by asset class. Because there usually is a lack of quoted market prices for long-lived assets, the fair value of impaired assets is typically determined based on the present values of expected future cash flows using discount rates believed to be consistent with those used by principal market participants or based on a multiple of operating cash flows validated with historical market transactions of similar assets where possible. The expected future cash flows used for impairment reviews and related fair value calculations are based on judgmental assessments of operating costs, project margins and capital project decisions, considering all available information at the date of review. If an impairment has occurred, we recognize a loss for the difference between the carrying amount and the fair value of the asset. In 2012, we recorded asset impairment charges of $14.6 million for the Intrepid, $157.8 million for the Caesar and related mobile pipelay equipment, and $4.6 million for well intervention assets associated with our former operations in Australia (Note 2). We did not record impairments related to our vessels during 2013 and 2011.

Assets are classified as held for sale when a formal plan to dispose of the assets exists and those assets meet the held for sale criteria. Assets held for sale are reviewed for potential loss on sale when we commit to a plan to sell and thereafter while the asset is held for sale. Losses are measured as the difference between the fair value less costs to sell and the asset’s carrying value. Estimates of anticipated sales prices are judgmental and subject to revision in future periods, although initial estimates are typically based on sales prices for similar assets and other valuation data.

Equity Investments

We periodically review our investments in Deepwater Gateway and Independence Hub for impairment. Under the equity method of accounting, an impairment loss would be recorded whenever a decline in value of an equity investment below its carrying amount is determined to be other than temporary. In judging "other than temporary," we would consider the length of time and extent to which the fair value of the investment has been less than the carrying amount of the equity investment, the near-term and long-term

Table of Contents

operating and financial prospects of the equity company and our longer-term intent of retaining the investment in the entity. We previously invested in an Australian joint venture that engaged in well intervention operations in the Southeast Asia region. We fully impaired our investment in that joint venture and recorded a $10.6 million other than temporary impairment charge in 2011. We exited this Australian joint venture in 2012 (Note 5).

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

As of December 31, 2013, we were exposed to market risk in two areas: interest rates and foreign currency exchange rates.

Interest Rate Risk. As of December 31, 2013, $292.5 million of our outstanding debt was subject to floating rates. The interest rate applicable to our variable rate debt may rise, increasing our interest expense and related cash outlay. To reduce the impact of this market risk, in September 2013, we entered into interest rate swap contracts to fix the interest rate on $148.1 million of our Term Loan debt. These swap contracts, which are settled monthly, began in October 2013 and extend through October 2016. The impact of market risk is estimated using a hypothetical increase in interest rates by 100 basis points for our variable rate long-term debt that is not hedged. Based on this hypothetical assumption, we would have incurred an additional $2.0 million in interest expense for the year ended December 31, 2013.

Foreign Currency Exchange Rate Risk. Because we operate in various regions in the world, we conduct a portion of our business in currencies other than the U.S. dollar (primarily with respect to Helix Well Ops (U.K.) Limited (“WOUK”)). The functional currency for WOUK is the applicable local currency (British Pound). Previously, WOSEA also had currency risk as its functional currency was the applicable local currency (Australian Dollar). We ceased operations in Australia in 2012. Although revenues are denominated in the local currency, the effects of foreign currency fluctuations are partly mitigated because the local expenses of such foreign operations are also generally denominated in the same currency.

Assets and liabilities of WOUK and WOSEA are translated using the exchange rates in effect at the balance sheet date, resulting in translation adjustments that are reflected in accumulated other comprehensive income (loss) in the shareholders’ equity section of our consolidated balance sheet. At December 31, 2013, approximately 18% of our assets are impacted by changes in foreign currencies in relation to the U.S. dollar. We recorded foreign currency translation unrealized gains (losses) of $5.0 million, $7.3 million and $(1.0) million to accumulated other comprehensive income (loss) for the years ended December 31, 2013, 2012 and 2011, respectively. Deferred taxes have not been provided on foreign currency translation adjustments since we consider our undistributed earnings (when applicable) of our non-U.S. subsidiaries to be permanently reinvested.

We also have other subsidiaries with operations in the United Kingdom, Asia Pacific, Europe and previously Australia. These international subsidiaries conduct the majority of their operations in these regions in U.S. dollars which is their functional currency. When currencies other than the U.S. dollar are to be paid or received, the resulting transaction gain or loss is recognized in the consolidated statements of operations as a component of other income (expense). These amounts resulted in a gains (loss) of $0.7 million, $(0.5) million and $(2.1) million for the years ended December 31, 2013, 2012 and 2011, respectively.

Our cash flows are subject to fluctuations resulting from changes in foreign currency exchange rates. Fluctuations in exchange rates are likely to impact our business and cash flows in the future. As a result, we entered into various foreign currency exchange contracts to stabilize expected cash outflows relating to certain vessel charters denominated in British pounds and Norwegian kroners. In January 2013, we entered into foreign currency exchange contracts to hedge through September 2017 the foreign currency exposure associated with the Grand Canyon charter payments ($104.6 million) denominated in Norwegian kroner (NOK591.3 million). In February 2013, we entered into similar foreign currency exchange contracts for the Grand Canyon II and the Grand Canyon III charter payments ($100.4 million and $98.8 million) denominated in Norwegian kroner (NOK594.7 million and NOK595.0 million), through July 2019 and February 2020, respectively. These contracts currently qualify for hedge accounting treatment. All of our remaining foreign exchange contracts are not accounted for as hedge contracts and changes in their fair value are being marked-to-market in earnings in each reporting period. The aggregate fair value of the foreign currency exchange contracts was a net liability of $15.0 million as of December 31, 2013 and a net asset of $0.1 million at December 31, 2012. The gains (losses) resulting from changes in the fair value of our foreign exchange contracts that were not designated for hedge accounting (Note 16) totaled $(0.6) million, $0.4 million and $0.2 million for the years ended December 31, 2013, 2012 and 2011, respectively.

Table of Contents

Item 8. Financial Statements and Supplementary Data.

INDEX TO FINANCIAL STATEMENTS

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The Company's management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. The Company's internal control system was designed to provide reasonable assurance to the Company's management and Board of Directors regarding the reliability of financial reporting and the preparation and fair presentation of financial statements for external purposes in accordance with U.S. generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In making its assessment, management has utilized the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") in Internal Control-Integrated Framework (1992 framework). Based on this assessment, management has concluded that, as of December 31, 2013, the Company's internal control over financial reporting is effective to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. generally accepted accounting principles.

The independent registered public accounting firm of Ernst & Young LLP, as auditors of the Company's consolidated financial statements, has issued an attestation report on the effectiveness of the Company's internal control over financial reporting as of December 31, 2013, which is included herein.

Table of Contents

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders of
Helix Energy Solutions Group, Inc. and Subsidiaries

We have audited Helix Energy Solutions Group, Inc. and subsidiaries' internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (1992 framework) (the COSO criteria). Helix Energy Solutions Group, Inc. and subsidiaries' management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Helix Energy Solutions Group, Inc. and subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Helix Energy Solutions Group, Inc. and subsidiaries as of December 31, 2013 and 2012, and the related consolidated statements of operations, comprehensive income (loss), shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2013 and our report dated February 21, 2014 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas
February 21, 2014

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
Helix Energy Solutions Group, Inc. and Subsidiaries

We have audited the accompanying consolidated balance sheets of Helix Energy Solutions Group, Inc. and subsidiaries as of December 31, 2013 and 2012, and the related consolidated statements of operations, comprehensive income (loss), shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2013. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We did not audit the financial statements of Deepwater Gateway, L.L.C. (a corporation in which the Company has a 50% interest) and Independence Hub, LLC (a corporation in which the Company has a 20% interest) as of December 31, 2012 and for each of the two years in the period ended December 31, 2012. In the consolidated financial statements, the Company’s equity investments includes approximately $168 million from Deepwater Gateway, L.L.C. and Independence Hub, LLC combined at December 31, 2012, and the Company’s equity in earnings of investments includes approximately $8 million and $20 million for the year in the period ended December 31, 2012 and 2011, respectively, from Deepwater Gateway, L.L.C. and Independence Hub, LLC combined. Those statements were audited by other auditors whose report has been furnished to us, and our opinion, insofar as it relates to the amounts included for Deepwater Gateway, L.L.C. and Independence Hub, LLC, is based solely on the report of the other auditors.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits and the reports of other auditors provide a reasonable basis for our opinion.

In our opinion, based on our audits and the reports of other auditors, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Helix Energy Solutions Group, Inc. and subsidiaries at December 31, 2013 and 2012, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2013, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Helix Energy Solutions Group, Inc. and subsidiaries’ internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (1992 framework) and our report dated February 21, 2014 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas
February 21, 2014

Table of Contents

REPORT OF INDEPENDENT REGISTERED ACCOUNTING FIRM

To the Management Committee of
Deepwater Gateway, L.L.C.
Houston, Texas

We have audited the balance sheets of Deepwater Gateway, L.L.C. (the “Company”) as of December 31, 2012 and 2011, and the related statements of operations, cash flows and members' equity for each of the two years in the period ended December 31, 2012 (not separately included herein). These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2012 and 2011, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2012 in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

Houston, Texas
February 15, 2013

Table of Contents

REPORT OF INDEPENDENT REGISTERED ACCOUNTING FIRM

To the Management Committee of
Independence Hub, LLC
Houston, Texas

We have audited the balance sheets of Independence Hub, LLC (the "Company") as of December 31, 2012 and 2011, and the related statements of operations, cash flows, and members' equity for each of the two years in the period ended December 31, 2012 (not separately included herein). These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2012 and 2011, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2012 in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

Houston, Texas
February 15, 2013

Table of Contents

HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in thousands)

	December 31, 2013	December 31, 2012
ASSETS		
Current assets:		
Cash and cash equivalents	$ 478,200	$ 437,100
Accounts receivable:		
Trade, net of allowance for uncollectible accounts of $2,234 and $5,152, respectively	156,925	152,233
Unbilled revenue	25,732	26,992
Costs in excess of billing	1,508	6,848
Current deferred tax assets	51,573	43,942
Other current assets	29,709	52,992
Current assets of discontinued operations	—	84,000
Total current assets	743,647	804,107
Property and equipment	1,959,783	2,051,796
Less accumulated depreciation	(431,489)	(565,921)
Property and equipment, net	1,528,294	1,485,875
Other assets:		
Equity investments	157,919	167,599
Goodwill	63,230	62,935
Other assets, net	51,190	49,837
Non-current assets of discontinued operations	—	816,227
Total assets	$ 2,544,280	$ 3,386,580
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 72,602	$ 92,398
Accrued liabilities	96,482	161,514
Income tax payable	760	—
Current maturities of long-term debt	20,376	16,607
Current liabilities of discontinued operations	—	182,527
Total current liabilities	190,220	453,046
Long-term debt	545,776	1,002,621
Deferred tax liabilities	265,879	359,237
Other non-current liabilities	18,295	5,025
Non-current liabilities of discontinued operations	—	147,237
Total liabilities	1,020,170	1,967,166
Commitments and contingencies		
Shareholders' equity:		
Common stock, no par, 240,000 shares authorized, 105,640 and 105,763 shares issued, respectively	933,507	932,742
Retained earnings	586,232	476,310
Accumulated other comprehensive loss	(20,688)	(15,667)

Total controlling interest shareholders' equity		1,499,051		1,393,385
Noncontrolling interests		25,059		26,029
Total equity		1,524,110		1,419,414
Total liabilities and shareholders' equity	$	2,544,280	$	3,386,580

The accompanying notes are an integral part of these consolidated financial statements.

Table of Contents

HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands, except per share amounts)

	Year Ended December 31,		
	2013	2012	2011
Net revenues	$876,561	$846,109	$702,000
Cost of sales:			
Cost of sales	615,876	619,059	545,753
Asset impairment charges	—	177,135	6,564
Total cost of sales	615,876	796,194	552,317
Gross profit	260,685	49,915	149,683
Loss on commodity derivative contracts	(14,113)	(10,507)	—
Gain (loss) on sale of assets, net	14,727	(13,476)	(6)
Selling, general and administrative expenses	(82,265)	(94,415)	(86,637)
Income (loss) from operations	179,034	(68,483)	63,040
Equity in earnings of investments	2,965	8,434	22,215
Other than temporary loss on equity investments	—	—	(10,563)
Net interest expense	(32,898)	(48,160)	(70,181)
Loss on early extinguishment of long-term debt	(12,100)	(17,127)	(2,354)
Other income (expense), net	6	(662)	(1,147)
Other income – oil and gas	6,581	—	—
Income (loss) before income taxes	143,588	(125,998)	1,010
Income tax provision (benefit)	31,612	(59,158)	(36,806)
Net income (loss) from continuing operations	111,976	(66,840)	37,816
Income from discontinued operations, net of tax	1,073	23,684	95,221
Net income (loss), including noncontrolling interests	113,049	(43,156)	133,037
Less net income applicable to noncontrolling interests	(3,127)	(3,178)	(3,098)
Net income (loss) applicable to Helix	$109,922	$(46,334)	$129,939
Basic earnings (loss) per share of common stock:			
Continuing operations	$1.03	$(0.67)	$0.33
Discontinued operations	0.01	0.23	0.90
Net income (loss) per common share	$1.04	$(0.44)	$1.23
Diluted earnings (loss) per share of common stock:			
Continuing operations	$1.03	$(0.67)	$0.33
Discontinued operations	0.01	0.23	0.90
Net income (loss) per common share	$1.04	$(0.44)	$1.23
Weighted average common shares outstanding:			
Basic	105,032	104,449	104,528
Diluted	105,184	104,449	104,953

The accompanying notes are an integral part of these consolidated financial statements.

Table of Contents

HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(in thousands)

	Year Ended December 31, 2013	2012	2011
Net income (loss), including noncontrolling interests	$113,049	$(43,156)	$133,037
Other comprehensive income (loss), net of tax:			
Unrealized gain (loss) on hedges arising during the period	(16,847)	(22,773)	22,551
Reclassification adjustments for (gain) loss included in net income	1,476	(2,661)	23,669
Reclassification adjustments for loss from derivatives de-designated as cash flow hedges included in net income	—	5,524	—
Income taxes on unrealized (gain) loss on hedges	5,380	6,969	(16,177)
Unrealized gain (loss) on hedges, net of tax	(9,991)	(12,941)	30,043
Foreign currency translation gain (loss)	4,970	7,291	(1,002)
Other comprehensive income (loss), net of tax	(5,021)	(5,650)	29,041
Comprehensive income (loss)	108,028	(48,806)	162,078
Less comprehensive income applicable to noncontrolling interests	(3,127)	(3,178)	(3,098)
Comprehensive income (loss) applicable to Helix	$104,901	$(51,984)	$158,980

The accompanying notes are an integral part of these consolidated financial statements.

Table of Contents

HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
(in thousands)

	Helix Energy Solutions Shareholders' Equity						
	Common Stock						
	Shares	Amount	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Controlling Interest Shareholders' Equity	Non-controlling interest	Total Equity
Balance, December 31, 2010	105,592	$ 906,957	$ 392,705	$ (39,058)	$ 1,260,604	$ 25,040	$ 1,285,644
Net income	—	—	129,939	—	129,939	3,098	133,037
Foreign currency translation adjustments	—	—	—	(1,002)	(1,002)	—	(1,002)
Unrealized gain on hedges, net	—	—	—	30,043	30,043	—	30,043
Stock compensation expense	—	8,418	—	—	8,418	—	8,418
Stock repurchases	(497)	(6,502)	—	—	(6,502)	—	(6,502)
Activity in company stock plans, net and other	435	916	—	—	916	—	916
Excess tax from stock-based compensation	—	(1,013)	—	—	(1,013)	—	(1,013)
Balance, December 31, 2011	105,530	$ 908,776	$ 522,644	$ (10,017)	$ 1,421,403	$ 28,138	$ 1,449,541
Net income (loss)	—	—	(46,334)	—	(46,334)	3,178	(43,156)
Foreign currency translation adjustments	—	—	—	7,291	7,291	—	7,291
Unrealized loss on hedges, net	—	—	—	(12,941)	(12,941)	—	(12,941)
Distributions to noncontrolling interests	—	—	—	—	—	(5,287)	(5,287)
Equity component of debt discount on Convertible Senior Note due 2032	—	22,419	—	—	22,419	—	22,419

Convertible preferred stock conversion (Note 2)	362	1,000	—	—	1,000	—	1,000
Stock compensation expense	—	7,361	—	—	7,361	—	7,361
Stock repurchases	(405)	(6,415)	—	—	(6,415)	—	(6,415)
Activity in company stock plans, net and other	276	787	—	—	787	—	787
Excess tax from stock-based compensation	—	(1,186)	—	—	(1,186)	—	(1,186)
Balance, December 31, 2012	105,763	$ 932,742	$ 476,310	$ (15,667)	$ 1,393,385	$ 26,029	$ 1,419,414
Net income	—	—	109,922	—	109,922	3,127	113,049
Foreign currency translation adjustments	—	—	—	4,970	4,970	—	4,970
Unrealized loss on hedges, net	—	—	—	(9,991)	(9,991)	—	(9,991)
Distributions to noncontrolling interests	—	—	—	—	—	(4,097)	(4,097)
Equity component of debt discount on Convertible Senior Note due 2032	—	49	—	—	49	—	49
Stock compensation expense	—	7,510	—	—	7,510	—	7,510
Stock repurchases	(390)	(8,855)	—	—	(8,855)	—	(8,855)
Activity in company stock plans, net and other	267	1,842	—	—	1,842	—	1,842
Excess tax from stock-based compensation	—	219	—	—	219	—	219
Balance, December 31, 2013	105,640	$ 933,507	$ 586,232	$ (20,688)	$ 1,499,051	$ 25,059	$ 1,524,110

The accompanying notes are an integral part of these consolidated financial statements.

Table of Contents

HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Year Ended December 31,		
	2013	2012	2011
Cash flows from operating activities:			
Net income (loss), including noncontrolling interests	$113,049	$(43,156)	$133,037
Adjustments to reconcile net income (loss), including noncontrolling interests to net cash provided by operating activities:			
Income from discontinued operations	(1,073)	(23,684)	(95,221)
Depreciation and amortization	98,535	97,201	91,188
Asset impairment charges	—	177,135	6,564
Amortization of deferred financing costs	5,187	9,086	8,910
Stock-based compensation expense	8,307	7,627	6,973
Amortization of debt discount	5,172	9,729	8,973
Deferred income taxes	(24,937)	(69,584)	(4,188)
Excess tax from stock-based compensation	(219)	1,186	1,013
Gain on investment in Cal Dive common stock	—	—	(753)
(Gain) loss on sale of assets, net	(14,727)	13,476	6
Loss on early extinguishment of debt	12,100	17,127	2,354
Other than temporary loss on equity investments	—	—	10,563
Unrealized (gain) loss and ineffectiveness on derivative contracts, net	77	(250)	382
Changes in operating assets and liabilities:			
Accounts receivable, net	(3,320)	(3,652)	(30,491)
Other current assets	14,277	(10,434)	18,783
Income tax payable	(56,164)	(16,812)	6,472
Accounts payable and accrued liabilities	(32,045)	73,448	23,191
Oil and gas asset retirement costs	(10,334)	(37,970)	(4,907)
Other noncurrent, net	(9,024)	(24,405)	(192)
Net cash provided by operating activities	104,861	176,068	182,657
Net cash provided by (used in) discontinued operations	(30,503)	276,430	384,498
Net cash provided by operating activities	74,358	452,498	567,155
Cash flows from investing activities:			
Capital expenditures	(324,426)	(323,039)	(100,154)
Distributions from equity investments, net	9,295	7,797	1,266
Proceeds from sale of assets	189,054	19,530	3,588
Net cash used in investing activities	(126,077)	(295,712)	(95,300)
Net cash provided by (used in) discontinued operations	582,965	(120,057)	(87,017)
Net cash provided by (used in) investing activities	456,888	(415,769)	(182,317)
Cash flows from financing activities:			
Early extinguishment of Senior Unsecured Notes	(281,490)	(209,500)	(77,394)
Borrowings under revolving credit facility	47,617	100,000	109,400
Repayment of revolving credit facility	(147,617)	—	(109,400)
Issuance of Convertible Senior Notes due 2032	—	200,000	—
Repurchase of Convertible Senior Notes due 2025	(3,487)	(298,288)	—
Proceeds from term loans	300,000	100,000	—

Repayment of term loans	(374,681)	(12,569)	(130,691)
Repayment of MARAD borrowings	(5,120)	(4,877)	(4,645)
Deferred financing costs	(10,954)	(7,580)	(9,311)
Distributions to noncontrolling interests	(4,097)	(5,287)	—
Repurchases of common stock	(11,256)	(7,197)	(7,604)
Excess tax from stock-based compensation	219	(1,186)	(1,013)
Exercise of stock options, net and other	734	1,252	763
Proceeds from issuance of ESPP shares	2,711	—	—
Net cash used in financing activities	(487,421)	(145,232)	(229,895)
Effect of exchange rate changes on cash and cash equivalents	(2,725)	(860)	436
Net increase (decrease) in cash and cash equivalents	41,100	(109,363)	155,379
Cash and cash equivalents:			
Balance, beginning of year	437,100	546,463	391,084
Balance, end of period	$478,200	$437,100	546,463

The accompanying notes are an integral part of these consolidated financial statements.

Table of Contents

HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1 — Organization

Effective March 6, 2006, we changed our name from Cal Dive International, Inc. to Helix Energy Solutions Group, Inc. ("Helix" or the "Company"). Unless the context indicates otherwise, the terms "we," "us" and "our" in this Annual Repor refer collectively to Helix and its subsidiaries. We are an international offshore energy company that provides specialty services to the offshore energy industry, with a focus on well intervention and robotics operations. We primarily conduct operations in the Gulf of Mexico, North Sea, Asia Pacific, and West Africa regions. Until June 2009, Cal Dive International, Inc. (collectively with its subsidiaries referred to as "Cal Dive") was a majority-owned subsidiary of Helix. We sold substantially all of our then remaining ownership interests in Cal Dive during 2009 (Note 2). In February 2013, we sold Energy Resource Technology GOM, Inc. ("ERT"), a former wholly-owned U.S. subsidiary that conducted our oil and gas operations in the Gulf of Mexico. Our former Oil and Gas segment was involved in prospect generation, exploration, development and production activities.

Our Operations

We seek to provide services and methodologies that we believe are critical to developing offshore reservoirs and maximizing production economics. Our "life of field" services are segregated into four disciplines: well intervention, robotics, subsea construction and production facilities. Historically, we reported our operations as two segments: Contracting Services and Production Facilities. With the completion of the sale of our two remaining subsea construction pipelay vessels and the continued emphasis on growing our well intervention and robotics businesses, we have disaggregated our former Contracting Services segment into three business segments: Well Intervention, Robotics and Subsea Construction (Note 14). Our Subsea Construction activities are now significantly diminished following the sale of substantially all of our existing assets related to this reportable segment. Our Production Facilities segment includes the majority ownership of the Helix Producer I (the "HP I") vessel as well as our equity investments in Deepwater Gateway, L.L.C. ("Deepwater Gateway") and Independence Hub, LLC ("Independence Hub") (Note 5). It also includes the Helix Fast Response System (the "HFRS"), which includes access to our Q4000 and HP I vessels. In 2011, we signed an agreement with Clean Gulf Associates ("CGA"), a non-profit industry group, allowing, in exchange for a retainer fee, the HFRS to be named as a response resource in permit applications to federal and state agencies and making the HFRS available to certain CGA participants who executed utilization agreements with us. In addition, we entered into separate utilization agreements with CGA members that specified the day rates to be charged should the HFRS be deployed in connection with a well control incident. The original set of agreements expired on March 31, 2013, and we entered into a new set of substantially similar agreements with the operators who formed HWCG LLC, a Delaware limited liability company comprised of some of the original CGA members as well as other industry participants to perform the same functions as CGA with respect to the HFRS. These agreements became effective April 1, 2013, and are for a four-year term.

Discontinued Operations

In December 2012, we announced a definitive agreement for the sale of ERT. On February 6, 2013, we sold ERT for $624 million plus additional consideration in the form of overriding royalty interests in ERT's Wang well and certain exploration prospects. As a result, we have presented the assets and liabilities included in the sale of ERT and the historical operating results of our former Oil and Gas segment as discontinued operations in the accompanying consolidated financial statements. See Note 3 for additional information regarding our discontinued oil and gas operations and Note 7 regarding the use of a portion of the sale proceeds to reduce our indebtedness under our former credit agreement.

Note 2 — Summary of Significant Accounting Policies

Principles of Consolidation

Our consolidated financial statements include the accounts of majority-owned subsidiaries. The equity method is used to account for investments in affiliates in which we do not have majority ownership, but have the ability to exert significant influence. We account for our Deepwater Gateway, Independence Hub and

Table of Contents

former Australian joint venture investments under the equity method of accounting. Noncontrolling interests represent the minority shareholders' proportionate share of the equity in Kommandor LLC (Note 6). All material intercompany accounts and transactions have been eliminated.

Reclassifications

Certain reclassifications were made to previously-reported amounts in the consolidated financial statements and notes thereto to make them consistent with the current presentation format. The most significant of these reclassifications are associated with our discontinued oil and gas operations. As noted in Note 1, ERT qualified as discontinued operations following the announcement of the definitive agreement for the sale of ERT. Accordingly, all operations and financial positions related to ERT have been presented as discontinued operations even if they did not qualify as a discontinued operation in that period.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Cash and Cash Equivalents

Cash and cash equivalents are highly liquid financial instruments with original maturities of three months or less. They are carried at cost plus accrued interest, which approximates fair value.

Statement of Cash Flow Information

The following table provides supplemental cash flow information for the periods stated (in thousands):

	Year Ended December 31,		
	2013	2012	2011
Interest paid, net of interest capitalized	$39,040	$68,735	$81,000
Income taxes paid	$113,331	$43,111	$11,216

Total non-cash investing activities for the years ended December 31, 2013, 2012 and 2011 include $9.5 million, $51.1 million and $26.1 million, respectively, of accruals for property and equipment capital expenditures.

Accounts Receivable and Allowance for Uncollectible Accounts

Accounts receivable are stated at the historical carrying amount net of write-offs and allowance for uncollectible accounts. The amount of our net accounts receivable approximates fair value. We establish an allowance for uncollectible accounts receivable based on historical experience and any specific customer collection issues that we have identified. Uncollectible accounts receivable are written off when a settlement is reached for an amount that is less than the outstanding historical balance or when we have determined that the balance will not be collected (Note 15).

Property and Equipment

Overview. Property and equipment is recorded at cost. Property and equipment is depreciated on a straight line basis over the estimated useful life of each respective asset. The following is a summary of the gross components of property and equipment (dollars in thousands):

Table of Contents

	Estimated Useful Life	2013	2012
ROVs/Vessels	10 to 30 years	$1,671,451	$1,822,642
Machinery, equipment, buildings and leasehold improvements	5 to 30 years	288,332	229,154
Total property and equipment		$1,959,783	$2,051,796

The cost of repairs and maintenance is charged to expense as incurred, while the cost of improvements is capitalized. Repair and maintenance expense totaled $31.5 million, $39.3 million and $32.3 million for the years ended December 31, 2013, 2012 and 2011, respectively. Included in machinery, equipment, buildings and leasehold improvements were $17.5 million and $18.5 million of capitalized software costs ($4.8 million and $6.0 million, net of accumulated amortization) at December 31, 2013 and 2012, respectively. The total amount charged to expense related to the amortization of these software costs was $1.8 million for the year ended December 31, 2013 and $2.6 million during each of the years ended December 31, 2012 and 2011.

Assets used in operations are assessed for impairment whenever changes in facts and circumstances indicate a possible significant deterioration in the future cash flows expected to be generated by an asset group. If, upon review, the sum of the undiscounted pretax cash flows is less than the carrying value of the asset group, the carrying value is written down to estimated fair value and reported as an impairment charge in the periods in which the determination of the impairment is made. Individual assets are grouped for impairment purposes at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets. Our marine vessels are assessed on a vessel by vessel basis, while our remotely operated vehicles (“ROVs”) are grouped and assessed by asset class. Because there usually is a lack of quoted market prices for long-lived assets, the fair value of impaired assets is typically determined based on the present values of expected future cash flows using discount rates believed to be consistent with those used by principal market participants or based on a multiple of operating cash flows validated with historical market transactions of similar assets where possible. The expected future cash flows used for impairment reviews and related fair value calculations are based on assessments of operating costs, project margins and capital project decisions, considering all available information at the date of review. If an impairment has occurred, we recognize a loss for the difference between the carrying amount and the fair value of the asset. These fair value measurements fall within Level 3 of the fair value hierarchy.

In 2011, in connection with the reorganization of our Australian well intervention operations, we conducted an impairment assessment of its well intervention equipment, which resulted in a $6.6 million charge to reduce the carrying value of such well intervention equipment to its then estimated fair value. In 2012, we decided to discontinue our well intervention operations in Australia. We recorded a $4.6 million impairment charge to reduce our well intervention assets in Australia to their fair value of $5.0 million. In 2012, as a result of diminished work opportunities for the Intrepid, we placed the subsea construction vessel in cold-stack mode and later sold the vessel for $14.5 million in cash, which resulted in asset impairment and related loss on disposal charges totaling $28.1 million. Also in 2012, we entered into an agreement to sell our two remaining subsea construction pipelay vessels, the Caesar and the Express, and other related pipelay equipment for a total sales price of $238.3 million. In connection with the announcement of the sale of our remaining subsea construction pipelay vessels and related equipment, we recorded an impairment charge of $157.8 million to reduce the carrying cost of the Caesar and other related pipelay equipment to their respective fair values as determined by the definitive sales agreement. In June 2013, we completed the sale of the Caesar and related equipment for $138.3 million, which amount included $30 million of funds deposited with us at the time the agreement was entered into by the parties. In July 2013, we completed the sale of the Express for $100 million, including the remaining $20 million of previously deposited funds. In June 2013, we entered into an agreement to sell our spoolbase property located in Ingleside, Texas for $45 million to the same group of companies that acquired the Caesar and the Express. In January 2014, we closed the sale of our Ingleside spoolbase. In connection with this sale, we received $15 million in cash, including a $5 million deposit we received at the time the agreement was signed, and hold a $30 million promissory note, in which a $10 million principal reduction in the note's balance is required to be paid to us on each December 31 in 2014, 2015 and 2016. See Note 3 for disclosure related to the impairment charges associated with certain of our former oil and gas properties.

Assets are classified as held for sale when we have a formalized plan for disposal and those assets meet the held for sale criteria. Our continuing operations had no assets meeting the requirements to be classified as assets held for sale at December 31, 2013 and 2012.

Interest from external borrowings is capitalized on major projects until the assets are ready for their intended use. Capitalized interest is added to the cost of the underlying asset and is amortized over the useful life of the asset in the same manner as the underlying asset. The total of our interest expense capitalized during each of the three years ended December 31, 2013, 2012 and 2011 was $10.4 million, $4.9 million and $1.3 million, respectively.

Equity Investments

We periodically review our equity investments in Deepwater Gateway and Independence Hub for impairment. Under the equity method of accounting, an impairment loss would be recorded whenever the fair value of an equity investment is determined to be below its carrying amount and the reduction is considered to be other than temporary. In judging "other than temporary," we would consider the length of time and extent to which the fair value of the investment has been less than the carrying amount of the equity investment, the near-term and long-term operating and financial prospects of the equity company and our longer-term intent of retaining the investment in the entity. We previously invested in an Australian joint venture that engaged in well intervention operations in the Southeast Asia region. We fully impaired our investment in that joint venture and recorded a $10.6 million other than temporary impairment charge in 2011. We exited this Australian joint venture in 2012.

Goodwill and Other Intangible Assets

We are required to perform an annual impairment analysis of goodwill. We elected November 1 to be our annual impairment assessment date for goodwill. However, we could be required to evaluate the recoverability of goodwill prior to the annual assessment date if we experience disruption to the business, unexpected significant declines in operating results, divestiture of a significant component of the business, emergence of unanticipated competition, loss of key personnel or a sustained decline in market capitalization. Our goodwill impairment test involves a comparison of the fair value with our carrying amount. The fair value is determined using discounted cash flows and other market-related valuation models. At the time of our annual assessment of goodwill on November 1, 2013, we had two reporting units with goodwill.

Goodwill impairment is determined using a two-step process. The first step is to identify if a potential impairment exists by comparing the fair value of the reporting unit with its carrying amount, including goodwill. If the fair value of a reporting unit exceeds its carrying amount, goodwill of the reporting unit is not considered to have a potential impairment and the second step of the impairment test is not necessary. However, if the carrying amount of a reporting unit exceeds its fair value, the second step is performed to determine if goodwill is impaired and to measure the amount of impairment loss to recognize, if any.

The second step compares the implied fair value of goodwill with the carrying amount of goodwill. If the implied fair value of goodwill exceeds the carrying amount, then goodwill is not considered impaired. However, if the carrying amount of goodwill exceeds the implied fair value, an impairment loss is recognized in an amount equal to that excess. The implied fair value of goodwill is determined in the same manner as the amount of goodwill recognized in a business combination (i.e., the fair value of the reporting unit is allocated to all the assets and liabilities, including any unrecognized intangible assets, as if the reporting unit were acquired in a business combination).

We use both the income approach and the market approach to estimate the fair value of our reporting units under the first step of our goodwill impairment assessment. Under the income approach, a discounted cash flow analysis is performed requiring us to make various judgmental assumptions about future revenue, operating margins, growth rates and discount rates. These judgmental assumptions are based on our budgets, long-term business plans, economic projections, anticipated future cash flows and market place data. Under the market approach, the fair value of each reporting unit is calculated by applying an average peer total invested capital EBITDA (defined as earnings before interest, income taxes and depreciation and amortization) multiple to the upcoming fiscal year's forecasted EBITDA for each reporting unit. Judgment is required when selecting peer companies that operate in the same or similar lines of business and are potentially subject to the same economic risks.

Our goodwill at December 31, 2013, 2012 and 2011 was associated with our Well Intervention and Robotics segments. In our 2013 goodwill impairment analysis, the fair value of both of our reporting units with goodwill exceeded their respective carrying value. Therefore, we concluded that our goodwill at December 31, 2013 was not impaired. As a result of the adoption of an update issued by the Financial

Table of Contents

Accounting Standards Board (the "FASB") in 2011 to simplify goodwill impairment testing, we performed qualitative assessments during 2012 and 2011 to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount including goodwill. Based on the then current and historical evidence supporting these reporting units' carrying value being sufficient to maintain their recorded goodwill amounts, we concluded that there was no indication of goodwill impairment and we did not perform the quantitative step one impairment analysis. We continue to monitor the current and future operations of these two reporting units to determine whether or not the quantitative assessment is once again necessary. We conduct the quantitative test at least every three years with the latest such test occurring on November 1, 2013.

The changes in the carrying amount of goodwill are as follows (in thousands):

	Well Intervention	Robotics	Total
Balance at December 31, 2011	$ 17,108	$ 45,107	$ 62,215
Other adjustments (1)	720	—	720
Balance at December 31, 2012	17,828	45,107	62,935
Other adjustments (1)	295	—	295
Balance at December 31, 2013	$ 18,123	$ 45,107	$ 63,230

(1) Reflects foreign currency adjustment for certain amounts of our goodwill.

Our intangible assets, other than goodwill, consist of intellectual property and patented technology related to our well intervention operations. We amortize these intangible assets on a straight-line basis over their estimated useful life or their legal life, whichever is shorter. At December 31, 2013, our remaining intangible assets, other than goodwill, totaled $1.9 million ($0.6 million, net of accumulated amortization of $1.3 million). Total amortization expense for intangible assets was $0.1 million for each of the years ended December 31, 2013, 2012, and 2011.

Recertification Costs and Deferred Dry Dock Charges

Our vessels are required by regulation to be recertified after certain periods of time. Recertification costs are incurred while a vessel is in dry dock. In addition, routine repairs and maintenance are performed and at times, major replacements and improvements are performed. We expense routine repairs and maintenance costs as they are incurred. We defer and amortize dry dock and related recertification costs over the length of time for which we expect to receive benefits from the dry dock and related recertification, which is generally 30 months but can be as long as 60 months if the appropriate permitting is obtained. A dry dock and related recertification process typically lasts one to two months, a period during which the vessel is idle and generally not available to earn revenue. Major replacements and improvements that extend the vessel's economic useful life or functional operating capability are capitalized and depreciated over the vessel's remaining economic useful life.

As of December 31, 2013 and 2012, capitalized deferred dry dock charges included within "Other assets, net" in the accompanying consolidated balance sheets (Note 4) totaled $24.8 million and $22.7 million, respectively, net of accumulated amortization of $14.5 million and $5.9 million, respectively. During the years ended December 31, 2013, 2012 and 2011, dry dock amortization expense was $14.8 million, $8.6 million and $7.6 million, respectively.

Convertible Preferred Stock

In December 2012, the holder of the remaining $1 million of Convertible Preferred Stock converted it into 361,402 shares of our common stock. We had previously presented the Convertible Preferred Stock below liabilities but not as a component of shareholders' equity, because we were, under certain instances, required to settle any future conversions in cash. The dividend rate was 4% for 2012 and 2011. Our Convertible Preferred Stock was assessed for inclusion in our diluted earnings per share calculation using the if converted method (see "Earnings Per Share") below.

Table of Contents

Revenue Recognition

Revenues from our services are derived from contracts, which are both short-term and long-term in duration. Our long-term services contracts are contracts that contain either lump-sum, turnkey provisions or provisions for specific time, material and equipment charges, which are billed in accordance with the terms of such contracts. We recognize revenue as it is earned at estimated collectible amounts. Further, we record revenues net of taxes collected from customers and remitted to governmental authorities.

Unbilled revenue represents revenue attributable to work completed prior to period end that has not yet been invoiced. All amounts included in unbilled revenue at December 31, 2013 and 2012 are expected to be billed and collected within one year.

Dayrate Contracts. Revenues generated from specific time, materials and equipment contracts are generally earned on a dayrate basis and recognized as amounts are earned in accordance with contract terms. In connection with these contracts, we may receive revenues for mobilization of equipment and personnel. Revenues related to mobilization are deferred and recognized over the period in which contracted services are performed using the straight-line method. Incremental costs incurred directly for mobilization of equipment and personnel to the contracted site, which typically consist of materials, supplies and transit costs, are also deferred and recognized using the same method. Our policy to amortize the revenues and costs related to mobilization on a straight-line basis over the estimated contract service period is consistent with the general pace of activity, level of services being provided and dayrates being earned over the service period of the contract. Mobilization costs to move vessels when a contract does not exist are expensed as incurred.

Turnkey Contracts. Revenue on significant turnkey contracts is recognized under the percentage-of-completion method based on the ratio of costs incurred to total estimated costs at completion. In determining whether a contract should be accounted for using the percentage-of-completion method, we consider whether:

- the customer provides specifications for the construction of facilities or for the provision of related services;
- we can reasonably estimate our progress towards completion and our costs;
- the contract includes provisions for the enforceable rights regarding the goods or services to be provided, consideration to be received, and the manner and terms of payment;
- the customer can be expected to satisfy its obligations under the contract; and
- we can be expected to perform our contractual obligations.

Under the percentage-of-completion method, we recognize estimated contract revenue based on costs incurred to date as a percentage of total estimated costs. Changes in the expected cost of materials and labor, productivity, scheduling and other factors affect the total estimated costs. Additionally, external factors, including weather and other factors outside of our control, may also affect the progress and estimated cost of a project's completion and, therefore, the timing of income and revenue recognition. We routinely review estimates related to our contracts and reflect revisions to profitability in earnings on a current basis. If a current estimate of total contract cost indicates an ultimate loss on a contract, we recognize the projected loss in full when it is first determined. We recognize additional contract revenue related to claims when the claim is probable and legally enforceable.

Whenever we have a contract that qualifies as a loss contract, we estimate the future shortfall between our anticipated future revenues and future costs.

Income Taxes

Deferred income taxes are based on the differences between financial reporting and tax bases of assets and liabilities. We utilize the liability method of computing deferred income taxes. The liability method is based on the amount of current and future taxes payable using tax rates and laws in effect at the balance sheet date. Income taxes have been provided based upon the tax laws and rates in the countries in which operations are conducted and income is earned. A valuation allowance for deferred tax assets is recorded when it is more likely than not that some or all of the benefit from the deferred tax asset will not be realized. We consider the undistributed earnings of our principal non-U.S. subsidiaries to be permanently reinvested.

Table of Contents

It is our policy to provide for uncertain tax positions and the related interest and penalties based upon management's assessment of whether a tax benefit is more likely than not to be sustained upon examination by tax authorities. At December 31, 2013, we believe we have appropriately accounted for any unrecognized tax benefits. To the extent we prevail in matters for which a liability for an unrecognized tax benefit is established or are required to pay amounts in excess of the liability, our effective tax rate in a given financial statement period may be affected.

Foreign Currency

Because we operate in various regions in the world, we conduct a portion of our business in currencies other than the U.S. dollar (primarily with respect to Helix Well Ops (U.K.) Limited ("WOUK")). The functional currency for WOUK is the applicable local currency (British Pound). Previously, our Australian well intervention subsidiary ("WOSEA") had the Australian Dollar as its functional currency. We ceased operations in Australia in 2012. Results of operations for these subsidiaries are translated into U.S. dollars using average exchange rates during the period. Assets and liabilities of these foreign subsidiaries are translated into U.S. dollars using the exchange rate in effect at December 31, 2013 and 2012 and the resulting translation adjustments, which were unrealized gains of $5.0 million and $7.3 million, respectively, are included in accumulated other comprehensive income (loss), a component of shareholders' equity. All foreign currency transaction gains and losses are recognized currently in the consolidated statements of operations.

Our foreign currency gains (losses) totaling $0.7 million in 2013, $(0.5) million in 2012 and $(2.1) million in 2011 are included in "Other income (expense), net" in the accompanying consolidated statements of operations. These realized amounts are exclusive of any unrealized gains or losses from our foreign currency exchange derivative contracts.

Derivative Instruments and Hedging Activities

Our continuing operations are exposed to market risks associated with interest rates and foreign currency exchange rates. Our risk management activities involve the use of derivative financial instruments to hedge the impact of market risk exposure related to variable interest rates and foreign currency exchange rates. All derivatives are reflected in the accompanying consolidated balance sheets at fair value.

We formally document all relationships between hedging instruments and the related hedged items, as well as our risk management objectives, strategies for undertaking various hedge transactions and our methods for assessing and testing correlation and hedge ineffectiveness. All hedging instruments are linked to the hedged asset, liability, firm commitment or forecasted transaction. We also assess, both at the inception of the hedge and on an on-going basis, whether the derivatives that are used in our hedging transactions are highly effective in offsetting changes in cash flows of the hedged items. We discontinue hedge accounting if we determine that a derivative is no longer highly effective as a hedge, or it is probable that a hedged transaction will not occur. If hedge accounting is discontinued because it is probable the hedged transaction will not occur, deferred gains or losses on the hedging instruments are recognized in earnings immediately. If the forecasted transaction continues to be probable of occurring, any deferred gains or losses in accumulated other comprehensive income (loss) are amortized to earnings over the remaining period of the original forecasted transaction.

We engage solely in cash flow hedges. Hedges of cash flow exposure are entered into to hedge a forecasted transaction or the variability of cash flows to be received or paid related to a recognized asset or liability. Changes in the derivative fair values that are designated as cash flow hedges are deferred to the extent that the hedges are effective. These fair value changes are recorded as a component of accumulated other comprehensive income or loss (a component of shareholders' equity) until the hedged transactions occur and are recognized in earnings. The ineffective portion of changes in the fair value of cash flow hedges is recognized immediately in earnings. In addition, any change in the fair value of a derivative that does not qualify for hedge accounting is recorded in earnings in the period in which the change occurs.

Table of Contents

Interest Rate Risk

We enter into interest rate swaps from time to time to stabilize cash flows related to our long-term debt subject to variable interest rates. Changes in the fair value of an interest rate swap are deferred to the extent the swap is effective. These changes are recorded as a component of accumulated other comprehensive income (loss) until the anticipated interest payments occur and are recognized in interest expense. The ineffective portion of the interest rate swap, if any, is recognized immediately in earnings within the line titled "Net interest expense." The amount of ineffectiveness associated with our interest rate swap contracts was immaterial for all periods presented.

Since January 2010, we had interest rate swap contracts to fix the interest rate on $200 million of indebtedness under our former credit facility. The last of these monthly contracts would have matured in January 2014. Under the terms of our former credit facility, we were required to use a portion of the proceeds from the sales of the Caesar, the Express and ERT to make payments to reduce our indebtedness. Because it was probable that we would pay off the corresponding indebtedness before the expiration of our interest rate swaps, we concluded in December 2012 that the swaps no longer qualified as cash flow hedges. Thus, at December 31, 2012, we recorded losses of approximately $0.6 million ($0.4 million net of tax) to reflect the mark-to-market adjustments for changes in the fair values of the interest rate swaps. In February 2013, we settled all of our interest rate swap contracts remaining at December 31, 2012 for $0.6 million.

In September 2013, we entered into interest rate swap contracts to fix the interest rate on $148.1 million of our Term Loan debt (Note 7). These monthly contracts began in October 2013 and extend through October 2016. The fair value of our remaining interest rate swaps was a net liability of $0.3 million and $0.5 million at December 31, 2013 and 2012, respectively.

Foreign Currency Exchange Rate Risk

Because we operate in various regions in the world, we conduct a portion of our business in currencies other than the U.S. dollar. We entered into various foreign currency exchange contracts to stabilize expected cash outflows relating to certain vessel charters that are denominated in British pounds and Norwegian kroner. The aggregate fair value of the foreign exchange contracts was a net liability of $15.0 million at December 31, 2013 and a net asset of $0.1 million at December 31, 2012.

In January 2013, we entered into foreign currency exchange contracts to hedge through September 2017 the foreign currency exposure associated with the Grand Canyon charter payments. In February 2013, we entered into similar foreign currency exchange contracts for the Grand Canyon II and the Grand Canyon III charter payments through July 2019 and February 2020, respectively. These contracts currently qualify for hedge accounting treatment. All of our remaining foreign exchange contracts are not accounted for as hedge contracts and changes in their fair value are being marked-to-market in earnings in each reporting period. We recorded gains (losses) totaling $(0.6) million in 2013, $0.4 million in 2012 and $0.2 million in 2011 associated with foreign exchange contracts not qualifying for hedge accounting.

See Note 16 for more information regarding the accounting for our derivative contracts including our commodity contracts associated with ERT.

Earnings Per Share

We have shares of restricted stock issued and outstanding, which remain subject to vesting requirements. Holders of such shares of unvested restricted stock are entitled to the same liquidation and dividend rights as the holders of our outstanding common stock and are thus considered participating securities. Under applicable accounting guidance, the undistributed earnings for each period are allocated based on the participation rights of both the common shareholders and holders of any participating securities as if earnings for the respective periods had been distributed. Because both the liquidation and dividend rights are identical, the undistributed earnings are allocated on a proportionate basis. Further, we are required to compute earnings per share ("EPS") amounts under the two class method in periods in which we have earnings from continuing operations. For periods in which we have a net loss we do not use the two class method as holders of our restricted shares are not contractually obligated to share in such losses.

Table of Contents

The presentation of basic EPS amounts on the face of the accompanying consolidated statements of operations is computed by dividing the net income applicable to Helix common shareholders by the weighted average shares of outstanding common stock. The calculation of diluted EPS is similar to basic EPS, except that the denominator includes dilutive common stock equivalents and the income included in the numerator excludes the effects of the impact of dilutive common stock equivalents, if any. The computations of the numerator (Income) and denominator (Shares) to derive the basic and diluted EPS amounts presented on the face of the accompanying consolidated statements of operations for the years ended December 31, 2013, 2012 and 2011 are as follows (in thousands):

	Year Ended December 31,					
	2013		2012		2011	
	Income	Shares	Income	Shares	Income	Shares
Basic:						
Continuing operations:						
Net income (loss) applicable to Helix	$ 109,922		$ (46,334)		$ 129,939	
Less: Income from discontinued operations, net of tax	(1,073)		(23,684)		(95,221)	
Income (loss) from continuing operations	108,849		(70,018)		34,718	
Less: Undistributed income allocable to participating securities – continuing operations	(801)		—		(427)	
Income (loss) applicable to common shareholders – continuing operations	$ 108,048	105,032	$ (70,018)	104,449	$ 34,291	104,528
Discontinued operations:						
Income from discontinued operations, net of tax	$ 1,073		$ 23,684		$ 95,221	
Less: Undistributed income allocable to participating securities – discontinued operations	(8)		—		(1,172)	
Income applicable to common shareholders – discontinued operations	$ 1,065	105,032	$ 23,684	104,449	$ 94,049	104,528

	Year Ended December 31,					
	2013		2012		2011	
	Income	Shares	Income	Shares	Income	Shares
Diluted:						
Continuing operations:						
Income (loss) applicable to common shareholders – continuing operations	$ 108,048	105,032	$ (70,018)	104,449	$ 34,291	104,528
Effect of dilutive securities:						
	—	152	—	—	—	64

Share-based awards other than participating securities						
Undistributed income reallocated to participating securities	1	—	—	—	2	—
Convertible preferred stock	—	—	—	—	40	361
Income (loss) applicable to common shareholders – continuing operations	$ 108,049	105,184	$ (70,018)	104,449	$ 34,333	104,953
Discontinued operations:						
Income from discontinued operations, net of tax	$ 1,073	105,184	$ 23,684	104,449	$ 95,221	104,953

We had net losses from continuing operations for the year ended December 31, 2012. Accordingly, our diluted EPS calculation for 2012 was equivalent to our basic EPS calculation because it excluded any assumed exercise or conversion of common stock equivalents because they were deemed to be anti-dilutive, meaning their inclusion would have reduced the reported net loss per share in those respective years. Shares that otherwise would have been included in the diluted per share calculations for the year ended December 31, 2012, assuming we had earnings from continuing operations, are as follows (in thousands):

Table of Contents

	2012
Diluted shares (as reported)	104,449
Share-based awards	382
Convertible preferred stock	334
Total	105,165

The diluted EPS calculation also excluded dividends and related costs associated with the convertible preferred stock that otherwise would have been added back to net income if assumed conversion of the shares was dilutive during the year.

No diluted shares were included for the 2032 Notes for the years ended December 31, 2013 and 2012 as the conversion price of $25.02 (and conversion trigger of $32.53 per share) was not met in either period, and because we have the right to settle any such future conversions in cash at our sole discretion (Note 7). No diluted shares were included for the 2025 Notes as the conversion price of $32.14 (and conversion trigger of $38.57 per share) was not met in the years ended December 31, 2012 and 2011.

Major Customers and Concentration of Credit Risk

The market for our products and services is primarily the offshore oil and gas industry. Oil and gas companies spend capital on exploration, drilling and production operations, the amount of which is generally dependent on the prevailing view of future oil and gas prices that are subject to many external factors which may contribute to significant volatility. Our customers consist primarily of major and independent oil and gas producers and suppliers, pipeline transmission companies, alternative (renewable) energy companies and offshore engineering and construction firms. We perform ongoing credit evaluations of our customers and provide allowances for probable credit losses when necessary. The percent of consolidated revenue from major customers, those whose total represented 10% or more of our consolidated revenues is as follows: 2013 — Shell (14%); 2012 — Shell (12%) and 2011 — Shell (10%). Most of the revenues from Shell were generated by our Well Intervention segment. We provided services to over 65 customers in 2013.

Fair Value Measurements

Current fair value accounting standards define fair value, establish a consistent framework for measuring fair value and expand disclosure for each major asset and liability category measured at fair value on either a recurring or nonrecurring basis. These standards also clarify that fair value is an exit price, representing the amount that would be received to sell an asset, or paid to transfer a liability, in an orderly transaction between market participants. These fair value accounting rules establish a three-tier fair value hierarchy, which prioritizes the inputs used in measuring fair value as follows:

- Level 1. Observable inputs such as quoted prices in active markets;
- Level 2. Inputs, other than the quoted prices in active markets, that are observable either directly or indirectly; and
- Level 3. Unobservable inputs for which there is little or no market data, which require the reporting entity to develop its own assumptions.

Assets and liabilities measured at fair value are based on one or more of three valuation techniques as follows:

(a) Market Approach. Prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities.

(b) Cost Approach. Amount that would be required to replace the service capacity of an asset (replacement cost).

(c) Income Approach. Techniques to convert expected future cash flows to a single present amount based on market expectations (including present value techniques, option-pricing and excess earnings models).

Table of Contents

Our financial instruments include cash and cash equivalents, accounts receivable, accounts payable, our long-term debt and various derivative instruments. The carrying amount of cash and cash equivalents, accounts receivable and accounts payable approximates fair value due to the highly liquid nature of these instruments. The following table provides additional information related to other financial instruments measured at fair value on a recurring basis at December 31, 2013 (in thousands):

	Level 1	Level 2 (1)	Level 3	Total	Valuation Technique
Assets:					
Foreign exchange contracts	$ —	$ 69	$ —	$ 69	(c)
Interest rate swaps	—	446	—	446	(c)
Liabilities:					
Fair value of long-term debt (2)	536,213	109,474	—	645,687	(a)
Foreign exchange contracts	—	15,071	—	15,071	(c)
Interest rate swaps	—	746	—	746	(c)
Total net liability	$ 536,213	$ 124,776	$ —	$ 660,989	

(1) Unless otherwise indicated, the fair value of our Level 2 derivative instruments reflects our best estimate and is based upon exchange or over-the-counter quotations whenever they are available. Quoted valuations may not be available due to location differences or terms that extend beyond the period for which quotations are available. Where quotes are not available, we utilize other valuation techniques or models to estimate market values. These modeling techniques require us to make estimations of future prices, price correlation and market volatility and liquidity based on market data. Our actual results may differ from our estimates, and these differences could be positive or negative.

(2) See Note 7 for additional information regarding our long-term debt. The fair value of our long-term debt at December 31, 2013 and 2012 is as follows (in thousands):

	2013		2012	
	Carrying Value	Fair Value (e)	Carrying Value	Fair Value (e)
Term Loans (mature July 2015) (a)	$—	$—	$367,181	$368,295
Revolving Credit Facility (matures July 2015) (a)	—	—	100,000	100,000
Term Loan (matures June 2018)	292,500	293,963	—	—
2025 Notes (mature December 2025) (b)	—	—	3,487	3,487
2032 Notes (mature March 2032) (c)	200,000	242,250	200,000	239,320
Senior Unsecured Notes (mature January 2016) (d)	—	—	274,960	283,209
MARAD Debt (matures February 2027)	100,168	109,474	105,288	123,187
Total debt	$592,668	$645,687	$1,050,916	$1,117,498

(a) Relates to the term loans and revolving credit facility under our former credit agreement, which was terminated in June 2013.
(b) This remaining amount was repurchased by us in February 2013.
(c) Carrying value excludes the related unamortized debt discount of $26.5 million at December 31, 2013.
(d) We redeemed our remaining Senior Unsecured Notes in July 2013.
(e) The estimated fair value of all debt, other than the MARAD debt, was determined using Level 1 inputs using the market approach. The fair value of the MARAD debt was determined using a third party evaluation of the

remaining average life and outstanding principal balance of the MARAD indebtedness as compared to other governmental obligations in the marketplace with similar terms. The fair value of the MARAD Debt was estimated using Level 2 fair value inputs using the market approach.

Table of Contents

Debt Discount

On January 1, 2009, we recorded a discount of $60.2 million related to our Convertible Senior Notes due 2025 (the “2025 Notes”) as required. To arrive at this discount amount, we estimated the fair value of the liability component of the 2025 Notes as of the date of their issuance (March 30, 2005) using an income approach. To determine this estimated fair value, we used borrowing rates of similar market transactions involving comparable liabilities at the time of issuance and an expected life of 7.75 years, which represented the earliest period that the holders could require us to repurchase the 2025 Notes (Note 7). The discount related to our 2025 Notes became fully amortized in December 2012.

In connection with the issuance of our Convertible Senior Notes due 2032 (the “2032 Notes”), we recorded a discount of $35.4 million under existing accounting requirements. To arrive at this discount amount, we estimated the fair value of the liability component of the 2032 Notes as of the date of their issuance (March 12, 2012) using an income approach. To determine this estimated fair value, we used borrowing rates of similar market transactions involving comparable liabilities at the time of issuance and an expected life of 6.0 years. In selecting the expected life, we selected the earliest date that the holders could require us to repurchase all or a portion of the 2032 Notes (March 15, 2018). The remaining unamortized amount of the discount of the 2032 Notes was $26.5 million at December 31, 2013 (Note 7).

Investment Available for Sale

In 2009 we sold substantially all of our owned shares of the publicly-traded Cal Dive common stock for net proceeds of $418.2 million, net of underwriting fees. Following these sale transactions, we owned 0.5 million shares of Cal Dive common stock, representing less than 1% of the total outstanding shares of Cal Dive. Accordingly we classified our remaining interest in Cal Dive as an investment available for sale. As an investment available for sale, the value of our remaining interest was marked-to-market at each period end with the corresponding change in value being reported as a component of accumulated other comprehensive income (loss) in the accompanying consolidated balance sheet. In March 2011, we sold our remaining 0.5 million shares of Cal Dive common stock on the open market for gross proceeds of $3.6 million resulting in a pre-tax gain of $0.8 million.

New Accounting Standards

We do not expect any recent accounting standards to have a material impact on our financial position, results of operations or cash flows.

Note 3 — Oil and Gas Properties

Results of Discontinued Operations

In December 2012, we announced a definitive agreement for the sale of ERT. On February 6, 2013, we sold ERT for $624 million plus additional consideration in the form of overriding royalty interests in ERT’s Wang well and certain exploration prospects. As a result, we have presented the assets and liabilities included in the sale of ERT and the historical operating results of our former Oil and Gas segment as discontinued operations in the accompanying consolidated financial statements.

The following summarized financial information relates to ERT, which is reported as “Income (loss) from discontinued operations, net of tax” in the accompanying consolidated statements of operations (in thousands):

Year Ended December 31,

	2013 (1)	2012	2011
Revenues	$48,847	$557,231	$696,607
Costs:			
Production (lifting) costs	16,017	164,663	176,269
Hurricane repair expense	—	662	(4,838)
Exploration expenses	3,514	3,295	10,914
Depreciation, depletion, amortization and accretion	1,226	158,284	219,915

Table of Contents

	Year Ended December 31,		
	2013 (1)	2012	2011
Proved property impairment and abandonment (2)	(152)	151,045	113,439
(Gain) loss on sale of oil and gas properties	—	1,714	(4,531)
Hedge ineffectiveness and non-hedge gain on commodity derivative contracts	—	(5,550)	—
Selling, general and administrative expenses	1,229	17,823	12,951
Net interest expense and other (3)	2,732	28,191	25,558
Total costs	24,566	520,127	549,677
Pretax income from discontinued operations	24,281	37,104	146,930
Income tax provision	8,499	13,420	51,709
Income from operations of discontinued operations	15,782	23,684	95,221
Loss on sale of business, net of tax	(14,709)	—	—
Income from discontinued operations, net of tax	$1,073	$23,684	$95,221

(1) Results for 2013 reflect the operating results from January 1, 2013 through February 6, 2013 when ERT was sold. There were no material results of operations for our former oil and gas segment subsequent to the sale of ERT.

(2) Results for 2012 include a charge of $138.6 million to reduce our carrying value of ERT to its estimated fair value less costs to sell.

(3) Net interest expense of $2.7 million, $27.7 million and $25.2 million for the years ended December 31, 2013, 2012 and 2011, respectively, was allocated to ERT and primarily consisted of interest associated with indebtedness directly attributed to the substantial oil and gas acquisition made in 2006. This includes interest related to debt required to be repaid upon the disposition of ERT.

Revenue Recognition for Royalty Interests

Revenues from royalty interests are recognized according to monthly oil and gas production on an entitlement basis. Revenues for royalty interests are reflected in "Other income – oil and gas" in the accompanying consolidated statements of operations.

United Kingdom Property

Since 2006, we have maintained an ownership interest in the Camelot field, located offshore in the North Sea. Modifications to U.K. regulations governing such operations required us to reassess our existing abandonment plan and cost estimates in 2011. The results of this review concluded that the scope of work to be performed in the abandoning of the wells in the field would be significantly expanded and as a result our cost estimates significantly increased. Based on our abandonment plan, we increased the asset retirement obligation by recording a corresponding $20.0 million charge to expense. At December 31, 2011, the remaining asset retirement obligation for the Camelot field was $27.3 million and our plan was to fully abandon the field in 2012 in accordance with applicable regulations in the United Kingdom.

During 2012, we recorded $15.5 million of additional charges to expense to reflect further increases in our estimated costs to complete our abandonment activities at Camelot, including the removal of certain environmentally sensitive materials. At December 31, 2012, the recorded asset retirement obligation for the Camelot field was $2.9 million.

During 2013, we recorded a $1.6 million charge reflecting the estimated final costs to complete our abandonment activities at Camelot. We completed the reclamation activities for this offshore property in 2013, including removing and appropriately disposing of all the related structures, and the plugging and abandoning of all the wells associated with the property. At December 31, 2013, the recorded asset retirement obligation was $1.1 million.

Table of Contents

Separately, we retained the reclamation obligations associated with one property located in the Gulf of Mexico pursuant to the terms of the ERT sale transaction. During 2013, we paid $5.2 million for our pro-rata share of the costs to complete the reclamation of this property.

The operating results and financial position associated with our U.K. property do not qualify for discontinued operations accounting treatment as this property was not classified as held for sale, and thus are reflected as continuing operations in our consolidated financial statements for all periods presented. Other than the impairment charges and asset retirement costs described above, the operating results associated with the Camelot field were immaterial for all periods presented in this Annual Report.

Note 4 — Details of Certain Accounts

Other current assets consisted of the following as of December 31, 2013 and 2012 (in thousands):

	2013	2012
Other receivables	$785	$1,086
Prepaid insurance	7,038	11,999
Other prepaids	12,999	11,751
Spare parts inventory	1,038	2,480
Income tax receivable	—	14,201
Derivative assets (Note 16)	69	5,946
Other	7,780	5,529
Total other current assets	$29,709	$52,992

Other assets, net, consisted of the following as of December 31, 2013 and 2012 (in thousands):

	2013	2012
Deferred dry dock expenses, net (Note 2)	$24,756	$22,704
Deferred financing costs, net (Note 7)	24,297	24,338
Intangible assets with finite lives, net	622	491
Other	1,515	2,304
Total other assets, net	$51,190	$49,837

Accrued liabilities consisted of the following as of December 31, 2013 and 2012 (in thousands):

	2013	2012
Accrued payroll and related benefits	$50,527	$51,561
Current asset retirement obligations	2,024	2,898
Unearned revenue (1)	19,608	6,137
Billing in excess of cost	1,677	6,445
Accrued interest (2)	4,187	17,451
Derivative liability (Note 16)	2,651	16,266
Taxes payable excluding income tax payable	4,811	5,164
Pipelay assets sale deposit (Note 2)	5,000	50,000
Other	5,997	5,592
Total accrued liabilities	$96,482	$161,514

(1) Increase primarily reflects fees associated with the mobilization of the Skandi Constructor to West Africa in December 2013. These fees will be amortized and recognized as revenue in the first quarter of 2014 as the project work associated with the mobilization is performed.

(2) Accrued interest at December 31, 2012 includes $12.2 million associated with our then remaining Senior Unsecured Notes which were fully redeemed in July 2013.

Table of Contents

Note 5 — Equity Investments

As of December 31, 2013, we had two investments that we account for using the equity method of accounting: Deepwater Gateway and Independence Hub, both of which are included in our Production Facilities segment.

Deepwater Gateway, L.L.C. In June 2002, we, along with Enterprise Products Partners L.P. (”Enterprise”), formed Deepwater Gateway, each with a 50% interest, to design, construct, install, own and operate a tension leg platform production hub primarily for Anadarko Petroleum Corporation's Marco Polo field in the Deepwater Gulf of Mexico. Our investment in Deepwater Gateway totaled $85.8 million and $91.4 million as of December 31, 2013 and 2012, respectively (including capitalized interest of $1.3 million and $1.3 million at December 31, 2013 and 2012, respectively).

Independence Hub, LLC. In December 2004, we acquired a 20% interest in Independence Hub, an affiliate of Enterprise. Independence Hub owns the "Independence Hub" platform located in Mississippi Canyon Block 920 in a water depth of 8,000 feet. Our investment in Independence Hub was $72.1 million and $76.2 million as of December 31, 2013 and 2012, respectively (including capitalized interest of $4.3 million and $4.6 million at December 31, 2013 and 2012, respectively).

We received the following distributions from our equity method investments during the years ended December 31, 2013, 2012 and 2011 (in thousands):

	Year Ended December 31,		
	2013	2012	2011
Deepwater Gateway	$7,600	$8,157	$7,600
Independence Hub	4,660	8,073	18,580
Total	$12,260	$16,230	$26,180

In February 2010, we announced the formation of a joint venture with an Australian-based engineering and construction company, Clough Limited (“Clough”), to provide a range of subsea services to offshore operators in the Asia Pacific region. Our contribution to the joint venture totaled $2.7 million in 2011 and our share of the income associated with the Australian joint venture’s operations was $2.1 million.

In December 2011, the marine construction and offshore engineering operations of Clough were acquired by a third party, including Clough’s 50% ownership interest in the joint venture. At December 31, 2011, we conducted an impairment assessment of our investment in the joint venture based on uncertainties concerning the continued availability of the Normand Clough and the limited backlog of existing projects at the time. We concluded that the $10.6 million carrying amount of the investment in the joint venture was fully impaired and recorded a $10.6 million other than temporary impairment charge in the accompanying consolidated statements of operations.

In the first quarter of 2012, we recorded additional losses totaling $3.8 million, including a $3.0 million fee when we negotiated our exit from the joint venture. In April 2012, we paid this fee. In connection with our exit, we were entitled to 50% of the value of certain of the net assets on hand at the time of our departure. We received approximately $3.7 million of proceeds for our pro rata portion of such assets of the joint venture, which was recorded as income in “Equity in earnings of investments” during the second quarter of 2012. We are no longer a participant in this Australian joint venture.

The summarized aggregated financial information related to the equity method investment is as follows (in thousands):

	Year Ended December 31,		
	2013	2012	2011
Revenues	$32,942	$53,159	$193,521
Operating income	10,058	30,463	97,954
Net income	10,058	30,463	93,215

77

Table of Contents

	December 31,		
	2013	2012	2011
Current assets	$10,314	$16,682	$39,754
Total assets	508,495	537,251	591,761
Current liabilities	90	706	11,012
Total liabilities	5,006	5,320	27,163

Note 6 — Kommandor LLC

In October 2006, we partnered with Kommandor RØMØ, a Danish corporation, to form Kommandor LLC, a Delaware limited liability company, the purpose of which was to convert a ferry vessel into a ship-shaped dynamically-positioned floating production unit vessel. Upon completion of the conversion in April 2009, the vessel, (the HP I) was leased to us under a bareboat charter. We subsequently installed topside oil and gas processing equipment, at 100% our cost, that allows the HP I to serve as a floating production system. The HP I will primarily service fields in the Deepwater of the Gulf of Mexico. In June 2010, the HP I was certified for use as a floating production unit by the U.S. Coast Guard. The HP I initially participated in the Macondo well control and containment efforts. Subsequently, the HP I mobilized to the Phoenix field where production commenced in October 2010. The HP I is under contract with ERT to service the Phoenix field through at least December 31, 2016.

The total cost of the conversion of the vessel was $148.7 million. The total cost of us to install the topside oil and gas processing facilities was $196.2 million.

We have recently reached agreement with Kommandor RØMØ to acquire its noncontrolling interests in Kommandor LLC for $20.1 million.

The consolidated results of Kommandor LLC are included in our Production Facilities segment. We owned approximately 81% of Kommandor LLC at December 31, 2013.

Note 7 — Long-Term Debt

Long-term debt consisted of the following as of December 31, 2013 and 2012 (in thousands):

	2013	2012
Term Loans (mature July 2015)	$—	$367,181
Revolving Credit Facility (matures July 2015)	—	100,000
Term Loan (matures June 2018)	292,500	—
2025 Notes (mature December 2025)	—	3,487
2032 Notes (mature March 2032)	200,000	200,000
Senior Unsecured Notes (mature January 2016)	—	274,960
MARAD Debt (matures February 2027)	100,168	105,288
Unamoritized debt discount	(26,516)	(31,688)
Total debt	566,152	1,019,228
Less current maturities	(20,376)	(16,607)
Long-term debt	$545,776	$1,002,621

Credit Agreement

In June 2013, we entered into a Credit Agreement (the "Credit Agreement") with a group of lenders pursuant to which we may borrow up to $300 million in a term loan (the "Term Loan") and may borrow revolving loans (the "Revolving Loans") under a revolving credit facility up to an outstanding amount of $600 million (the "Revolving Credit Facility"). The Revolving Credit Facility also permits us to obtain letters of credit up to the full amount of the Revolving Credit Facility. Subject to customary conditions, we may request an increase of up to $200 million in aggregate commitments with respect to the Revolving Credit Facility, additional term loans or a combination thereof. In July 2013, we borrowed $300 million under the Term Loan in connection with our early redemption of the remaining $275 million Senior Unsecured Notes outstanding (see "Senior Unsecured Notes" below).

The Term Loan and the Revolving Loans (together, the "Loans"), at our election, will bear interest either in relation to the base rate established by Bank of America N.A. or to a LIBOR rate, provided that all Swing Line Loans (as defined in the Credit Agreement) will be base rate loans. The Term Loan currently bears interest at the LIBOR Rate plus 2.5%. In September 2013, we entered into interest rate swap contracts to fix the interest rate on $148.1 million of the Term Loan (Note 16).

The Loans or portions thereof bearing interest at the base rate will bear interest at a per annum rate equal to the base rate plus a margin ranging from 1.00% to 2.00%. The Loans or portions thereof bearing interest at a LIBOR rate will bear interest at the LIBOR rate selected by us plus a margin ranging from 2.00% to 3.00%. A letter of credit fee is payable by us equal to our applicable margin for LIBOR rate Loans multiplied by the daily amount available to be drawn under outstanding letters of credit. Margins on the Loans will vary in relation to the consolidated coverage ratio, as provided by the Credit Agreement. We also pay a fixed commitment fee of 0.5% on the unused portion of our Revolving Credit Facility. At December 31, 2013, our availability under the Revolving Credit Facility totaled $584.2 million, net of $15.8 million of letters of credit issued.

The Term Loan is repayable in scheduled principal installments of 5% in each of the initial two loan years ($15 million per year), and 10% in each of the remaining three loan years ($30 million per year), payable quarterly, with a balloon payment of $180 million at maturity. These installment amounts are subject to adjustment for any prepayments on the Term Loan. We may elect to prepay amounts outstanding under the Term Loan without premium or penalty, but may not reborrow any amounts prepaid. We may prepay amounts outstanding under the Revolving Loans without premium or penalty, and may reborrow any amounts paid up to the amount of the Revolving Credit Facility. The Loans mature on June 19, 2018. In certain circumstances, we will be required to prepay the Loans.

The Credit Agreement and the other documents entered into in connection with the Credit Agreement (together, the "Loan Documents") include terms and conditions, including covenants, which we consider customary for this type of transaction. The covenants include restrictions on our and our subsidiaries' ability to grant liens, incur indebtedness, make investments, merge or consolidate, sell or transfer assets, pay dividends and incur capital expenditures. In addition, the Credit Agreement obligates us to meet certain financial ratios, including the Consolidated Interest Coverage Ratio and the Consolidated Leverage Ratio (as defined in the Credit Agreement). We may designate one of our existing foreign subsidiaries, and any newly established foreign subsidiaries, as subsidiaries that are not generally subject to the covenants in the Credit Agreement (the "Unrestricted Subsidiaries"), provided we meet certain liquidity requirements, in which case the EBITDA of the Unrestricted Subsidiaries is not included in the calculations for our financial covenants. Our obligations under the Credit Agreement are guaranteed by our domestic subsidiaries (except Cal Dive I – Title XI, Inc.) and Canyon Offshore Limited. Our obligations under the Credit Agreement, and of the guarantors under their guaranty, are secured by most of our assets and assets of the guarantors and Canyon Offshore Limited, plus pledges of up to two thirds of the shares of certain foreign subsidiaries.

Former Credit Facility

Our former credit facility also contained both term loan and revolving loan components. This indebtedness was scheduled to mature on July 1, 2015. In February 2013, we repaid $318.4 million of borrowings outstanding under our former credit facility with the proceeds from the sale of ERT. In connection with the repayment of this debt in February 2013, we recorded a $2.9 million charge to accelerate a pro rata portion of the deferred financing costs associated with our former term loan debt. This charge is reflected as a component of "Loss on early extinguishment of long-term debt" in the accompanying consolidated statements of operations.

In June 2013, we fully repaid the remaining $70.3 million of indebtedness outstanding under our former credit facility. Prior to that repayment, the principal amounts outstanding were reduced by the repayment of $80.1 million of the proceeds from the sale of the Caesar in June 2013 (Note 2). Our former credit facility was replaced by our new

Credit Agreement in June 2013. In connection with the repayment and termination of our former credit agreement, we recorded a $0.6 million charge to accelerate the remaining deferred financings costs associated with our indebtedness under the term loan component of our former credit facility. This charge is also a component of “Loss on early extinguishment of long-term debt” in the accompanying consolidated statements of operations.

Table of Contents

Senior Unsecured Notes

In December 2007, we issued $550 million of 9.5% Senior Unsecured Notes due 2016 (the "Senior Unsecured Notes"). Interest on the Senior Unsecured Notes was payable semi-annually in arrears on each January 15 and July 15, commencing July 15, 2008. The Senior Unsecured Notes were fully and unconditionally guaranteed by substantially all of our existing restricted domestic subsidiaries, except for Cal Dive I-Title XI, Inc. The Indenture governing the Senior Unsecured Notes provided that, prior to their stated maturity, we may redeem all or a portion of the Senior Unsecured Notes on no less than 30 days' and no more than 60 days' prior notice at the redemption prices (expressed as percentages of the principal amount) set forth below, plus accrued and unpaid interest thereon, if any, to the applicable redemption date.

Year	Redemption Price
2013	102.375%
2014 and thereafter	100.000%

In 2011, we purchased a portion of our Senior Unsecured Notes that resulted in the early extinguishment of an aggregate $75.0 million of those notes. In these transactions we paid an aggregate amount of $77.4 million, including $75.0 million in principal and $2.4 million in premium. We also paid the accrued interest on these Senior Unsecured Notes totaling $0.8 million and we recorded a $0.9 million charge to interest expense to accelerate a pro rata portion of the deferred financing costs associated with the issuance of the Senior Unsecured Notes in 2007.

At December 31, 2011, we had $475.0 million of Senior Unsecured Notes outstanding. In March 2012, we purchased $200.0 million of the balance then outstanding of our Senior Unsecured Notes. For this purchase, we paid a total of $213.5 million, including $200.0 million in principal, a $9.5 million call premium and $4.0 million of accrued and unpaid interest. This purchase resulted in a loss on early extinguishment of debt totaling $11.5 million, which reflects the $9.5 million call premium and a $2.0 million charge to accelerate a pro rata portion of the deferred financing costs associated with the issuance of the Senior Unsecured Notes. The loss on this early extinguishment of these notes is reflected as a component of "Loss on early extinguishment of long-term debt" in the accompanying consolidated statements of operations.

At December 31, 2012, we had $275.0 million of Senior Unsecured Notes outstanding. In June 2013, we elected to redeem our remaining Senior Unsecured Notes. On July 22, 2013, we paid $282.0 million to fully redeem the Senior Unsecured Notes, including $275.0 million with respect to the principal amount outstanding, $6.5 million of call premium and $0.5 million in accrued and unpaid interest. Our 2013 results of operations include a loss on early extinguishment of debt totaling $8.6 million, which reflects the $6.5 million call premium and a $2.1 million charge to accelerate the remaining deferred financing costs associated with the original issuance of the Senior Unsecured Notes.

Convertible Senior Notes Due 2032

In March 2012, we completed a public offering and sale of $200.0 million in aggregate principal amount of 3.25% Convertible Senior Notes due 2032. The net proceeds from the issuance of the 2032 Notes were $195.0 million, after deducting the underwriter's discounts and commissions and offering expenses. We used the net proceeds to repurchase and retire $142.2 million of aggregate principal amount of the 2025 Notes (see below) in separate, privately negotiated transactions. The remaining net proceeds were used for other general corporate purposes, including the repayment of other indebtedness.

The 2032 Notes bear interest at a rate of 3.25% per annum, and are payable semi-annually in arrears on March 15 and September 15 of each year, beginning on September 15, 2012. The 2032 Notes will mature on March 15, 2032, unless earlier converted, redeemed or repurchased. The 2032 Notes are convertible in certain circumstances and during certain periods at an initial conversion rate of 39.9752 shares of common stock per $1,000 principal amount (which represents an initial conversion price of approximately $25.02 per share of common stock), subject to adjustment in certain circumstances as set forth in the Indenture governing the 2032 Notes. The initial conversion price represents a conversion premium of 35.0% over the closing price of our common stock on March 6, 2012 of $18.53 per share.

Table of Contents

Prior to March 20, 2018, the 2032 Notes are not redeemable. On or after March 20, 2018, we, at our option, may redeem some or all of the 2032 Notes in cash, at any time, upon at least 30 days' notice at a price equal to 100% of the principal amount plus accrued and unpaid interest (including contingent interest, if any) up to but excluding the redemption date. In addition, holders may require us to purchase in cash some or all of their 2032 Notes at a repurchase price equal to 100% of the principal amount of the 2032 Notes, plus accrued and unpaid interest (including contingent interest, if any) up to but excluding the applicable repurchase date, on March 15, 2018, March 15, 2022 and March 15, 2027, or, subject to specified exceptions, at any time prior to the 2032 Notes' maturity following a fundamental change (as defined in the governing indenture).

In connection with the issuance of the 2032 Notes, we recorded a discount of $35.4 million as required under existing accounting rules. To arrive at this discount amount, we estimated the fair value of the liability component of the 2032 Notes as of the date of their issuance (March 12, 2012) using an income approach. To determine this estimated fair value, we used borrowing rates of similar market transactions involving comparable liabilities at the time of issuance and an expected life of 6.0 years. In selecting the expected life, we selected the earliest date that the holder could require us to repurchase all or a portion of the 2032 Notes (March 15, 2018). The effective interest rate for the 2032 Notes is 6.9% after considering the effect of the accretion of the related debt discount that represented the equity component of the 2032 Notes at their inception.

Our weighted average share price for 2013 and 2012 was below the $25.02 per share conversion price (and conversion trigger of $32.53 per share). As a result, there are no shares included in our diluted earnings per share calculation associated with the assumed conversion of the 2032 Notes (Note 2).

MARAD Debt

This U.S. government guaranteed financing (the "MARAD Debt") is pursuant to Title XI of the Merchant Marine Act of 1936 administered by the Maritime Administration, and was used to finance the construction of the Q4000. The MARAD Debt is payable in equal semi-annual installments beginning in August 2002 and matures in February 2027. The MARAD Debt is collateralized by the Q4000, is guaranteed 50% by us, and initially bore interest at a floating rate that approximated AAA Commercial Paper yields plus 20 basis points. As provided for in the MARAD Debt agreements, in September 2005, we fixed the interest rate on the debt through the issuance of a 4.93% fixed-rate note with the same maturity date.

Convertible Senior Notes Due 2025

In March 2005, we issued $300 million of 3.25% Convertible Senior Notes due 2025 at 100% of the principal amount to certain qualified institutional buyers. The effective interest rate for the 2025 Notes was 6.6% after considering the effect of the accretion of the related debt discount that represented the equity component of the 2025 Notes at their inception.

In connection with the issuance of additional Convertible Senior Notes (see "Convertible Senior Notes Due 2032" above) in March 2012, we repurchased $142.2 million in aggregate principal of the 2025 Notes. In these repurchase transactions we paid an aggregate amount of $145.1 million, representing principal plus $1.8 million of premium and $1.1 million of accrued interest. The loss on this early extinguishment of the 2025 Notes totaled $5.6 million and is reflected as a component of "Loss on early extinguishment of long-term debt" in the accompanying consolidated statements of operations. The loss includes the acceleration of $3.5 million of unamortized discount associated with the 2025 Notes, the $1.8 million premium paid in connection with the repurchase of a portion of the 2025 Notes and a $0.3 million charge to accelerate a pro rata portion of the deferred financing costs associated with the original issuance of the 2025 Notes. The remainder of the 2025 Notes was extinguished when the holders exercised their option for us to repurchase their notes in December 2012 ($154.3 million) and in February 2013 when we repurchased the remaining $3.5 million of the 2025 Notes that were not put to us in December 2012.

Our weighted average share price for 2013, 2012 and 2011 was below the $32.14 per share conversion price. As a result, there are no shares included in our diluted earnings per share calculation associated with the assumed conversion of the 2025 Notes.

Table of Contents

Other

In accordance with our Credit Agreement, 2032 Notes and MARAD Debt agreements, we are required to comply with certain covenants, including certain financial ratios such as a consolidated interest coverage ratio and consolidated leverage ratio, as well as the maintenance of minimum net worth, working capital and debt-to-equity requirements. As of December 31, 2013, we were in compliance with these covenants and restrictions.

We paid financing costs associated with our debt totaling $11.0 million in 2013 and $7.6 million in 2012. Unamortized deferred financing costs are included in "Other assets, net" in the accompanying consolidated balance sheets and are amortized over the life of the respective debt agreements. The following table reflects the components of our deferred financing costs for the years ended December 31, 2013 and 2012 (in thousands):

	December 31, 2013			December 31, 2012		
	Gross Carrying Amount	Accumulated Amortization	Net	Gross Carrying Amount	Accumulated Amortization	Net
Term Loans (mature July 2015) (1)	$ —	$ —	$ —	$ 15,318	$ (11,595)	$ 3,723
Revolving Credit Facility (matures July 2015) (1)	—	—	—	20,021	(12,466)	7,555
Term Loan (matures June 2018) (2)	3,638	(364)	3,274	—	—	—
Revolving Credit Facility (matures June 2018) (2)	13,275	(1,327)	11,948	—	—	—
2025 Notes (mature December 2025)	—	—	—	8,189	(8,189)	—
2032 Notes (mature March 2032)	3,759	(1,148)	2,611	4,251	(534)	3,717
Senior Unsecured Notes (mature January 2016) (3)	—	—	—	10,643	(8,252)	2,391
MARAD Debt (matures February 2027)	12,200	(5,736)	6,464	12,200	(5,248)	6,952
Total deferred financing costs	$ 32,872	$ (8,575)	$ 24,297	$ 70,622	$ (46,284)	$ 24,338

(1) Relates to the term loans and revolving credit facility under our former credit agreement, which was terminated in June 2013.

(2) Relates to amounts allocated to the existing Term Loan and Revolving Credit Facility, which became effective in June 2013.

(3) In July 2013, we redeemed our remaining Senior Unsecured Notes. In connection with this redemption, we recorded a charge of $2.1 million to accelerate the remaining deferred financing costs associated with the original issuance of this debt.

Scheduled maturities of long-term debt outstanding as of December 31, 2013 are as follows (in thousands):

	Term	MARAD	2032	Total

	Loan (1)	Debt	Notes (2)	
Less than one year	$15,000	$5,376	$—	$20,376
One to two years	22,500	5,644	—	28,144
Two to three years	30,000	5,926	—	35,926
Three to four years	30,000	6,222	—	36,222
Four to five years	195,000	6,532	—	201,532
Over five years	—	70,468	200,000	270,468
Total debt	292,500	100,168	200,000	592,668
Current maturities	(15,000)	(5,376)	—	(20,376)
Long-term debt, less current maturities	277,500	94,792	200,000	572,292
Unamortized debt discount (3)	—	—	(26,516)	(26,516)
Long-term debt	$277,500	$94,792	$173,484	$545,776

Table of Contents

(1) The amount reflects the borrowings made in July 2013 (see Credit Agreement discussion above).

(2) Beginning in March 2018, the holders of the 2032 Notes may require us to repurchase these notes or we may at our option elect to repurchase notes. These notes will mature in March 2032.

(3) The 2032 Notes will increase to their principal amount through accretion of non-cash interest charges through March 2018.

The following table details our interest expense and capitalized interest for the years ended December 31, 2013, 2012 and 2011 (in thousands):

	Year Ended December 31,		
	2013	2012	2011
Interest expense (1)	$44,484	$53,601	$72,824
Interest income	(1,167)	(548)	(1,366)
Capitalized interest	(10,419)	(4,893)	(1,277)
Net interest expense	$32,898	$48,160	$70,181

(1) Interest expense of $2.8 million, $28.6 million and $25.8 million for 2013, 2012 and 2011, respectively, was allocated to ERT and is included in discontinued operations. Following the sale of ERT in February 2013, we ceased allocation of interest expense to ERT, which constitutes a discontinued operation.

Note 8 — Income Taxes

We and our subsidiaries, including acquired companies (as of their respective dates of acquisition), file a consolidated U.S. federal income tax return. We believe our recorded assets and liabilities are reasonable; however, tax laws and regulations are subject to interpretation and tax litigation is inherently uncertain, and therefore our assessments can involve a series of complex judgments about future events and rely heavily on estimates and assumptions.

Components of income tax provision (benefit) on continuing operations reflected in the consolidated statements of operations consisted of the following (in thousands):

	Year Ended December 31,		
	2013	2012	2011
Current	$57,128	$6,572	$(78,150)
Deferred	(25,516)	(65,730)	41,344
	$31,612	$(59,158)	$(36,806)
Domestic	$11,615	$(78,211)	$(51,590)
Foreign	19,997	19,053	14,784
	$31,612	$(59,158)	$(36,806)

Income taxes have been provided based on the U.S. statutory rate of 35% and at the local statutory rate for each foreign jurisdiction adjusted for items which are allowed as deductions for federal and foreign income tax reporting purposes, but not for book purposes. The primary differences between the statutory rate and our effective rate from continuing operations are as follows:

Table of Contents

	Year Ended December 31,		
	2013	2012	2011
Statutory rate	35.0 %	35.0 %	35.0 %
Foreign provision	(11.6)	11.2	(291.0)
Effect of Australian reorganization	—	—	(2,984.3)
Other	(1.4)	0.8	(265.0)
Effective rate	22.0 %	47.0 %	(3,505.3) %

In 2011, we reorganized our Australian operating companies. The reorganization resulted in a recorded net tax benefit of $31.3 million associated with the impairment of our U.S. investment in the Australian subsidiaries.

Deferred income taxes result from the effect of transactions that are recognized in different periods for financial and tax reporting purposes. The nature of these differences and the income tax effect of each as of December 31, 2013 and 2012 are as follows (in thousands):

	2013	2012
Deferred tax liabilities:		
Depreciation and depletion	$169,404	$336,471
Original Issue Discount on 2025 and 2032 Notes	14,720	13,098
Equity investments in production facilities	84,870	81,082
Prepaid and other	7,556	10,548
Total deferred tax liabilities	$276,550	$441,199
Deferred tax assets:		
Net operating losses	$(40,105)	$(36,981)
Asset retirement obligations	(708)	(70,085)
Reserves, accrued liabilities and other	(44,291)	(35,229)
Total deferred tax assets	(85,104)	(142,295)
Valuation allowance	22,860	16,391
Net deferred tax liabilities	$214,306	$315,295
Deferred income tax is presented as:		
Current deferred tax assets	(51,573)	(43,942)
Noncurrent deferred tax liabilities	265,879	359,237
Net deferred tax liabilities	$214,306	$315,295

At December 31, 2013, our U.S. net operating losses available for carryforward or carryback totaled $49.3 million and our foreign tax credits available for carryforward or carryback totaled $9.8 million. The net operating loss carryforward would expire in 2030, while the foreign tax credit carryforward would expire in 2020. At this time, we anticipate utilizing these tax attributes via carryback claims. At December 31, 2013, we had a $22.9 million valuation allowance related to certain non-U.S. deferred tax assets, primarily net operating losses generated in Australia, as management believed it is more likely than not that we will not be able to utilize the tax benefit. Additional valuation allowances may be made in the future if in management's opinion it is more likely than not that the tax benefit will not be utilized. Any limitations on our ability to utilize our tax benefit carryforward could result in an increase in our federal income tax liability in future taxable periods.

We consider the undistributed earnings of our principal non-U.S. subsidiaries to be permanently reinvested. At December 31, 2013 and 2012, our principal non-U.S. subsidiaries had accumulated earnings and profits of approximately $202.6 million and $167.9 million, respectively. We have not provided deferred U.S. income tax on the accumulated earnings and profits as we consider them permanently reinvested.

Table of Contents

We had $4.7 million related to uncertain tax positions as of December 31, 2013. In 2012, we reversed a $2.8 million long-term liability related to an uncertain tax position that was projected to be included on our 2011 tax return. The tax position was not taken when the 2011 tax return was filed. We account for tax-related interest in interest expense and tax penalties in selling, general and administrative expenses. We charged $0.2 million to income tax expense for interest and penalties accrued in each of 2013, 2012 and 2011, which brought our total liabilities for interest and penalties to $1.3 million and $1.1 million in the accompanying consolidated balance sheets at December 31, 2013 and 2012, respectively. As of December 31, 2013, 2012, and 2011, there were $3.4 million, $3.4 million and $6.2 million, respectively, of unrecognized tax benefits that if recognized would affect the annual effective rate. A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows (in thousands):

	2013	2012	2011
Balance at January 1,	$4,506	$7,085	$4,085
Additions based on tax positions related to current year	—	—	2,785
Additions for tax positions of prior years	217	206	215
Reductions for tax positions of prior years	—	(2,785)	—
Balance at December 31,	$4,723	$4,506	$7,085

We file tax returns in the U.S. and in various state, local and non-U.S. jurisdictions. We anticipate that any potential adjustments to our state, local and non-U.S. jurisdiction tax returns by tax authorities would not have a material impact on our financial position. The tax periods ending December 31, 2010, 2009, 2008, 2007 and 2006 are under examination by the U.S. Internal Revenue Service ("IRS"). The tax periods ended December 31, 2013, 2012 and 2011 remain open to future review and examination by the IRS. In non-U.S. jurisdictions, the open tax periods include 2013, 2012, 2011, 2010 and 2009.

Note 9 — Employee Benefit Plans

Defined Contribution Plan

We sponsor a defined contribution 401(k) retirement plan covering substantially all of our employees. Our contributions are in the form of cash and, prior to 2014, consisted of a 50% match of each employee's contribution up to 5% of the employee's salary. Beginning in 2014, our matching contributions increased to 75% of the first 5% of the employee's salary. Our costs related to the 401(k) plan totaled $1.7 million, $1.6 million and $1.4 million for the years ended December 31, 2013, 2012 and 2011, respectively.

Stock-Based Compensation Plans

We have two stock-based compensation plans: the 1995 Long-Term Incentive Plan, as amended (the "1995 Incentive Plan") and the 2005 Long-Term Incentive Plan, as amended and restated effective May 9, 2012 (the "2005 Incentive Plan").

Upon adoption of the 1995 Incentive Plan in May 1995, a maximum of 10% of the total shares of common stock issued and outstanding were eligible to be granted to executive officers, selected management employees and non-employee members of our Board of Directors. Following the approval by shareholders of the 2005 Incentive Plan in May 2005, no further grants have been or will be made under the 1995 Incentive Plan.

In May 2012, the shareholders approved an amendment to and restatement of the 2005 Incentive Plan to: (i) authorize 4.3 million additional shares for issuance pursuant to our equity incentive compensation strategy, (ii) authorize incentive stock options, stock appreciation rights, cash awards and performance awards to be made pursuant to the

2005 Incentive Plan, and (iii) include performance criteria for awards that may be made contingent upon the achievement of one or more performance measures, as well as limits on individual awards, in accordance with the requirements for performance-based compensation under Section 162(m) of the Internal Revenue Code. As of December 31, 2013, there were 6.6 million shares available for issuance under the 2005 Incentive Plan, which includes a maximum of 2.0 million shares that may be granted as incentive stock options.

Table of Contents

The 1995 and 2005 Incentive Plans are administered by the Compensation Committee of Helix's Board of Directors. The Compensation Committee also determines the type of award to be made to each participant and, as set forth in the related award agreement, the terms, conditions and limitations applicable to each award. The Compensation Committee may grant stock options, restricted stock, restricted stock units, and cash awards. Prior to 2012, awards granted to employees under the incentive plans vested 20% per year over a five-year period. Commencing in 2012, awards granted under the 2005 Incentive Plan have a vesting period of three years (or 33% per year). There have been no stock options granted since 2004. Stock options granted have a maximum exercise life of 10 years.

Compensation cost for restricted shares is the product of grant date fair value of each share and the number of shares granted and is recognized over the respective vesting periods on a straight-line basis. Forfeitures on restricted stock totaled approximately 7% based on our most recent five-year average of historical forfeiture rates. Tax deduction benefits for an award in excess of recognized compensation cost is reported as a financing cash flow rather than as an operating cash flow. Stock based compensation that is based solely on service conditions is recognized on a straight line basis over the vesting period of the related shares.

Stock Options

The following table summarizes information about our stock options during the years ended December 31, 2013, 2012 and 2011:

	2013		2012		2011	
	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Options outstanding at beginning of year	52,800	$13.91	192,800	$10.52	432,918	$10.78
Exercised	(52,800)	13.91	(140,000)	9.24	(181,670)	10.92
Terminated	—	—	—	—	(58,448)	11.20
Options outstanding at end of year	—	$—	52,800	$13.91	192,800	$10.52
Options exercisable at end of year	—	$—	52,800	$13.91	192,800	$10.52

There was no compensation recognized associated with stock options in 2013, 2012 or 2011 as all stock options outstanding are vested. The aggregate intrinsic value of the stock options exercised in 2013, 2012 and 2011 was approximately $0.5 million, $1.3 million and $1.1 million, respectively. There were no stock option awards remaining at December 31, 2013. The aggregate intrinsic value of options exercisable at December 31, 2012 and 2011 was approximately $0.4 million and $1.0 million, respectively.

Share-based Awards

We grant share-based awards (restricted stock, restricted stock units ("RSUs") and/or performance share units ("PSUs")) to members of our Board of Directors, executive officers and selected management employees. The following table summarizes information about our share-based awards during the years ended December 31, 2013, 2012 and 2011:

2013	2012	2011

	Shares	Grant Date Fair Value (1)	Shares	Grant Date Fair Value (1)	Shares	Grant Date Fair Value (1)
Awards outstanding at beginning of year	1,324,312	$15.09	1,263,218	$14.80	1,463,298	$16.93
Granted	257,797	24.86	482,340	18.33	571,163	12.77
Vested (2)	(518,240)	17.70	(400,180)	18.07	(504,813)	19.87
Forfeited	(108,254)	16.49	(21,066)	15.00	(266,430)	12.55
Awards outstanding at end of year (3)	955,615	$16.16	1,324,312	$15.09	1,263,218	$14.80

Table of Contents

(1) Represents the weighted average grant date fair value, which is based on the quoted market price of the common stock on the business day prior to the date of grant.

(2) Total fair value of share-based awards that vested during the years ended December 31, 2013, 2012 and 2011 was $11.4 million, $6.7 million and $6.7 million, respectively.

(3) Includes 67,520 shares of RSUs with the grant date fair value of $15.80 per share. In December 2013, management elected to pay out the January 2014 vesting of these RSUs in cash. As a result, we recorded a $1.3 million liability associated with these RSUs at December 31, 2013. We paid $0.8 million of this liability in January 2014.

For the years ended December 31, 2013, 2012 and 2011, $8.8 million, $7.7 million, $8.4 million, respectively, was recognized as stock-based compensation expense related to share-based awards. Future compensation cost associated with unvested share-based awards at December 31, 2013, 2012, and 2011 totaled approximately $14.2 million, $13.2 million and $12.0 million, respectively. The weighted average vesting period related to unvested share-based awards at December 31, 2013 was approximately 1.5 years.

The following grants of share-based awards were made in 2013 under the 2005 Incentive Plan:

Date of Grant	Shares	Grant Date Fair Value Per Share	Vesting Period
January 2, 2013 (1)	89,329	$ 20.64	33% per year over three years
January 2, 2013 (2)	89,329	30.96	100% on January 1, 2016
January 2, 2013 (3)	1,620	20.64	100% on January 1, 2015
April 1, 2013 (3)	2,814	22.88	100% on January 1, 2015
July 1, 2013 (3)	2,740	23.04	100% on January 1, 2015
October 1, 2013 (3)	2,389	25.37	100% on January 1, 2015
December 5, 2013 (4)	53,358	22.49	33% per year over three years

(1) Reflects the grant of restricted shares to our executive officers.

(2) Reflects the grant of performance share units ("PSUs") to our executive officers. The estimated fair value of the PSUs on grant date was determined using a Monte Carlo simulation model. The PSUs provide for an award based on the performance of our common stock over a three-year period with the maximum award being 200% of the original awarded PSUs and the minimum amount being zero. The vested PSUs will be settled in an equivalent number of shares of our common stock unless the Compensation Committee of our Board of Directors elects to pay in cash.

(3) Reflects the grant of restricted shares to certain members of our Board of Directors who have made an election to take their quarterly fees in stock in lieu of cash.

(4) Reflects annual equity grants to each member of our Board of Directors.

In January 2014, we granted our executive officers 73,609 restricted shares under the 2005 Long-Term Incentive Plan. The market value of the restricted shares was $23.18 per share or $1.7 million and the shares vest 33% per year for a three-year period. Separately, we issued our executive officers 73,609 PSUs. The PSUs provide for an award based on the performance of our common stock over a three-year period with the maximum amount of the award being 200% of the original awarded PSUs and the minimum amount being zero. The PSUs vest 100% on the three-year anniversary date of the grant. The vested PSUs will be settled in an equivalent number of shares of our common stock unless the Compensation Committee of our Board of Directors determines to pay in cash.

Stock Compensation Modifications

Under our 1995 Incentive Plan and our 2005 Long-Term Incentive Plan, upon a stock recipient's termination of employment, which is defined as employment with us and any of our majority-owned subsidiaries, any unvested restricted stock and stock options are forfeited immediately, and all unexercised vested options are forfeited as specified under the applicable plan or agreement.

Table of Contents

Employee Stock Purchase Plan

In May 2012, the shareholders approved the Helix Energy Solutions Group, Inc. Employee Stock Purchase Plan (the "ESPP"). The ESPP has 1.5 million shares authorized for issuance, of which 1.3 million shares were available for issuance as of December 31, 2013. Eligible employees who participate in the ESPP may purchase shares of our common stock through payroll deductions on an after-tax basis over a four-month period beginning on January 1, May 1, and September 1 of each year during the term of the ESPP, subject to certain restrictions and limitations established by the Compensation Committee of our Board of Directors and Section 423 of the Internal Revenue Code. The per share price of common stock purchased under the ESPP is equal to 85% of the lesser of (i) its fair market value on the first trading day of the purchase period or (ii) its fair market value on the last trading day of the purchase period. The first purchase period under the ESPP began on September 1, 2012. The total value of the ESPP awards is calculated using the component approach where each award is computed as the sum of 15% of a share of non-vested stock, a call option on 85% of a share of non-vested stock, and a put option on 15% of a share of non-vested stock. Share-based compensation expense with respect to the ESPP was $0.8 million and $0.3 million for the years ended December 31, 2013 and 2012, respectively.

Long-Term Incentive Cash Plan

In January 2009, we adopted the 2009 Long-Term Incentive Cash Plan (the "2009 LTI Plan") to provide long-term cash compensation to eligible employees. Our executive officers and selected management employees as designated from time to time by the Compensation Committee of our Board of Directors are granted cash awards. Under the terms of the 2009 LTI Plan, cash awards historically have been both fixed sum amounts payable (for non-executive management only) as well as cash awards indexed to our common stock with the payment amount at each vesting date fluctuating based on the performance of our common stock (for both executive and non-executive management). These are measured based on the performance of our stock price over the applicable award period compared to a base price determined by the Compensation Committee of our Board of Directors at the time of the award. The measurement period to determine the annual payment for the share-based cash awards is generally the last 20 trading days of the year prior to a vesting (the last 30 trading days for the 2009 awards). Payment amounts are based on the calculated ratio of the average stock price during the applicable measurement period over the original base price as determined by the Compensation Committee of our Board of Directors. The maximum amount payable under these share-based cash awards is twice the original targeted award and if the average price during the measurement period is less than 75% (50% for 2010 grants) of the base price, no payout will be made at the applicable anniversary date. Payments under the 2009 LTI Plan are made each year on the anniversary date of the award. The 2005 Incentive Plan also permits long-term cash awards to eligible employees. Awards granted prior to 2012 have a vesting period of five years and awards granted in 2014, 2013 and 2012 have a vesting period of three years. This share-based component is considered a liability plan and as such is re-measured to fair value each reporting period with corresponding changes being recorded as a charge to earnings.

The cash awards granted under the 2005 Incentive Plan and the 2009 LTI Plan (the "LTI Plans") totaled $8.4 million in 2013, $4.2 million in 2012, and $5.2 million in 2011. These awards were made to our executive officers and selected management employees in 2013 and solely to our executive officers in 2012 and 2011. Total compensation expense associated with the cash awards issued pursuant to the LTI Plans was $9.1 million ($5.3 million related to our executive officers), $8.7 million ($7.3 million related to our executive officers) and $7.9 million ($6.5 million related to our executive officers), respectively, for the years ended December 31, 2013, 2012 and 2011, respectively. The liability balance for the cash awards issued under the LTI Plans was $14.8 million at December 31, 2013 and $13.0 million at December 31, 2012, including $11.1 million at December 31, 2013 and $11.7 million at December 31, 2012 associated with the cash awards issued to our executive officers under the LTI plans. During 2013, 2012 and 2011, we paid $7.1 million, $5.5 million and $5.9 million of the liability associated with the LTI plans. In January 2014, we paid $9.2 million of the liability balance as of December 31, 2013. In January 2014, $8.9 million was awarded under the LTI Plans to executive officers and selected management employees.

Table of Contents

Note 10 — Shareholders' Equity

Our amended and restated Articles of Incorporation provide for authorized Common Stock of 240,000,000 shares with no stated par value per share and 5,000,000 shares of preferred stock, $0.01 par value per share issuable in one or more series.

The components of accumulated other comprehensive loss as of December 31, 2013 and 2012 are as follows (in thousands):

	2013	2012
Cumulative foreign currency translation adjustment	$(10,697)	$(15,667)
Unrealized loss on hedges, net (1)	(9,991)	—
Accumulated other comprehensive loss	$(20,688)	$(15,667)

(1) Amount at December 31, 2013 is related to foreign currency hedges for the Grand Canyon, the Grand Canyon II and the Grand Canyon III as well as interest rate swap contracts we entered into in September 2013, and is net of deferred income taxes totaling $5.4 million (Notes 7 and 16).

Note 11 — Stock Buyback Program

In June 2009, we announced that we intended to purchase up to 1.5 million shares of our common stock plus an amount equal to additional shares of our common stock granted under our stock-based compensation plans (Note 9) as permitted under our Credit Agreement (Note 7). Our Board of Directors had previously granted us the authority to repurchase shares of our common stock in an amount equal to any equity issued to our employees, officers and directors under our stock-based compensation plans, including share-based awards issued under our existing LTI Plans and shares issued to our employees under our employee stock purchase plans (Note 9). We may continue to make repurchases pursuant to this authority from time to time as additional equity is issued under our stock based plans depending on prevailing market conditions and other factors. As described in an announced plan, all repurchases may be commenced or suspended at any time as determined by management. During 2013, we purchased 389,721 shares as then available under this program for $8.8 million or an average of $22.72 per share. As of December 31, 2013, we had repurchased a total of 3,268,514 shares of our common stock for $45.8 million or an average of $14.01 per share.

Note 12 — Related Party Transactions

Our Chief Executive Officer, Owen Kratz, through Class A limited partnership interests in OKCD Investments, Ltd. ("OKCD"), personally owns approximately 85% of the partnership. OKCD receives a royalty from ERT, which was a wholly owned subsidiary of Helix until ERT was sold in February 2013. Payments to OKCD during the period in which Helix owned ERT totaled $0.6 million, $6.9 million and $8.3 million in the years ended December 31, 2013, 2012 and 2011, respectively.

A former member of our Board of Directors is part of the senior management team of Weatherford International, Ltd (Weatherford). This individual resigned from our Board of Directors in May 2011. We paid Weatherford, an oil and gas industry company, $3.6 million for services provided to us in 2011.

Note 13 — Commitments and Contingencies and Other Matters

Commitments

Commitments Related to Expansion of Well Intervention Fleet

In March 2012, we executed a contract with a shipyard in Singapore for the construction of a newbuild semi-submersible well intervention vessel, the Q5000. This $386.5 million shipyard contract represents the majority of the expected costs associated with the construction of the Q5000. Pursuant to the terms of this contract, payments are made in a fixed percentage of the contract price, together with any variations, on contractually scheduled dates. At December 31, 2013, our total investment in the Q5000 was $210.6 million, including $173.8 million of scheduled payments made to the shipyard.

Table of Contents

In July 2012, we contracted to charter the Skandi Constructor for use in our North Sea well intervention operations. The vessel was delivered to us on April 1, 2013. The initial term of the charter will expire in March 2016.

In August 2012, we acquired the Discoverer 534 drillship from a subsidiary of Transocean Ltd. for $85 million. The vessel, renamed the Helix 534, underwent upgrades and modifications to render it suitable for use as a well intervention vessel and commenced well intervention operations in February 2014. At December 31, 2013, our investment in the acquisition and subsequent upgrades to and modifications of the Helix 534 totaled $202.8 million, including related well control equipment.

In January 2013, we contracted to charter the Rem Installer for use in our robotics operations. The vessel was delivered to us in July 2013. The initial term of the charter will expire in July 2016.

In February 2013, we contracted to charter the Grand Canyon II and the Grand Canyon III for use in our robotics operations. The terms of the charters will be five years from the respective delivery dates, which are expected to be in 2014 and 2015.

In September 2013, we executed a second contract with the same shipyard in Singapore that is currently constructing the Q5000. This contract provides for the construction of a newbuild semi-submersible well intervention vessel, the Q7000, which will be built to North Sea standards. This $346.0 million shipyard contract represents the majority of the expected costs associated with the construction of the Q7000. Pursuant to the terms of this contract, 20% of the contract price was paid upon the signing of the contract and the remaining 80% will be paid upon the delivery of the vessel. At December 31, 2013, our total investment in the Q7000 was $76.7 million, including the $69.2 million paid to the shipyard upon signing the contract.

Lease Commitments

We lease several facilities and vessels under non-cancelable operating leases expiring at various dates through 2025. Future minimum rentals under these leases at December 31, 2013 are as follows (in thousands):

	Vessels	Facilities and Other	Total
2014	$ 119,672	$ 3,433	$ 123,105
2015	144,478	4,242	148,720
2016	109,155	3,864	113,019
2017	80,705	3,881	84,586
2018	47,595	3,917	51,512
Thereafter	45,938	21,550	67,488
Total lease commitments	$ 547,543	$ 40,887	$ 588,430

Total rental expense under these operating leases was approximately $102.1 million, $85.0 million and $62.2 million for the years ended December 31, 2013, 2012 and 2011, respectively.

We sublease part of our corporate headquarters facility to a third party under a non-cancelable sublease agreement. Total rental income from this sublease was $0.4 million in 2013. As of December 31, 2013, the minimum rentals to be received in the future totaled $2.4 million.

Contingencies and Claims

Under terms of the equity purchase agreement for the sale of ERT, we required the buyer to provide bonding in a sufficient amount as determined by the Bureau of Ocean Energy Management (the "BOEM") to cover the decommissioning costs of ERT's lease properties and thus to replace and allow for a full discharge of our existing guaranty to the BOEM for ERT's lease obligations. The buyer posted the bonding required by the equity purchase agreement, and a formal request to the BOEM for a release of our guaranty is pending.

Table of Contents

In 2007, we were subcontracted to perform development work for a large gas field offshore India. Work commenced in the fourth quarter of 2007 and we completed our scope of work in the third quarter of 2009. We had collected approximately $303 million related to this project with an amount of uncollected trade receivables remaining. In 2010, we requested arbitration in India pursuant to the terms of the subcontract to pursue our claims and the prime contractor also requested arbitration and asserted certain counterclaims against us. Based on a number of factors associated with ongoing negotiations with the prime contractor, in 2010, we reduced our trade receivable balance to an amount that we believed to be ultimately realizable. The parties have been engaged in extensive settlement discussions over time to resolve this matter outside of the arbitration process, and in December 2013 the parties reached a settlement agreement, pursuant to which we collected the receivable and the parties dropped all claims against each other.

We are currently undergoing a value added tax ("VAT") audit from the State of Andhra Pradesh, India (the "State") for the tax years 2010, 2009, 2008 and 2007 related to an Indian subsea construction and diving contract that we entered into in December 2006. We believe that we have complied with all rules and regulations as related to VAT in the State and we anticipate no additional assessments as a result of this audit.

Litigation

On July 8, 2011, a shareholder derivative lawsuit styled City of Sterling Heights Police & Fire Retirement System v. Owen Kratz, et al. was filed in the United States District Court for the Southern District of Texas, Houston Division. In the suit, the plaintiff makes claims against our Board of Directors, certain of our former directors, certain of our current and former executive officers, and the independent compensation consultant to the Compensation Committee of our Board of Directors, for breaches of the fiduciary duty of loyalty, unjust enrichment and aiding and abetting the alleged breaches of fiduciary duty relating to the long-term equity awards granted in 2010 to certain of the Company's then executive officers who are defendants. The defendants filed a motion to dismiss the claim asserting that the plaintiff has not (i) pled specific facts excusing its failure to make pre-suit demand on our Board of Directors as required by Minnesota law; (ii) filed proper verification; or (iii) stated a claim. A ruling regarding the motion is pending.

On May 12, 2012, a shareholder derivative lawsuit styled Mark Lucas v. Owen Kratz, et al. was filed in the 270th Judicial District in the District Court of Harris County, Texas. In the suit, the plaintiff makes claims against our Board of Directors, certain of our former directors, certain of our current and former executive officers, and the independent compensation consultant to the Compensation Committee of our Board of Directors, for breaches of the fiduciary duties of candor, good faith and loyalty, unjust enrichment and aiding and abetting the alleged breaches of fiduciary duty relating to the long-term equity awards granted in 2010 to certain of our executive officers. This case is essentially a "copycat" complaint asserting similar causes of action arising out of the same facts as set forth in the federal action described above. The plaintiff is generally demanding disgorgement of the excessive compensation, restraint on the disposition/exercise of the alleged improperly awarded equity, implementation of additional internal controls, and attorney's fees and costs of litigation. The defendants filed motions to stay and dismiss the proceeding, which motions were denied by the trial court judge. The defendants then filed a petition for a writ of mandamus with the state appellate court, in which they requested that court to direct the district court to grant the motion to stay or dismiss the case. The appellate court denied the request to grant mandamus with respect to this requested relief, but did grant a writ of mandamus ordering the lower court to vacate its ruling to the extent the plaintiff failed to plead with particularity that our Board of Directors wrongfully refused his demand, and that he was a shareholder of record at the relevant time. A special committee of our Board of Directors has since determined to reject the plaintiff's demand regarding this matter, and based on this rejection, as well as the plaintiff's pleadings, the defendants filed a motion for summary judgment in December 2013, which is pending before the court.

We are involved in various legal proceedings, primarily involving claims for personal injury under the General Maritime Laws of the United States and the Jones Act based on alleged negligence. In addition, from time to time we incur other claims, such as contract disputes, in the normal course of business.

Table of Contents

Insurance

We maintain Hull and Increased Value insurance which provides coverage for physical damage up to an agreed amount for each vessel. The deductibles are $1.0 million on the Q4000, the HP I and the Well Enhancer, $500,000 on the Seawell and the Helix 534. In addition to the primary deductibles, the vessels are subject to an annual aggregate deductible of $5 million. We also carry Protection and Indemnity ("P&I") insurance which covers liabilities arising from the operation of the vessels and General Liability insurance which covers liabilities arising from construction operations. The deductible on both the P&I and General Liability is $100,000 per occurrence. Onshore employees are covered by Workers' Compensation. Offshore employees and marine crews are covered by a Maritime Employers Liability ("MEL") insurance policy which covers Jones Act exposures and includes a deductible of $100,000 per occurrence plus a $1.0 million annual aggregate deductible. In addition to the liability policies described above, we currently carry various layers of Umbrella Liability for total limits of $500 million excess of primary limits. Our self-insured retention on our medical and health benefits program for employees is $250,000 per participant.

We incur workers' compensation, MEL, and other insurance claims in the normal course of business, which management believes are covered by insurance. The Company analyzes each claim for potential exposure and estimates the ultimate liability of each claim. At December 31, 2013, we did not have any claims exceeding our deductible limits. We have not incurred any significant losses as a result of claims denied by our insurance carriers. Our services are provided in hazardous environments where accidents involving catastrophic damage or loss of life could occur, and litigation arising from such an event may result in our being named a defendant in lawsuits asserting large claims. Although there can be no assurance the amount of insurance we carry is sufficient to protect us fully in all events, or that such insurance will continue to be available at current levels of cost or coverage, we believe that our insurance protection is adequate for our business operations. A successful liability claim for which we are underinsured or uninsured could have a material adverse effect on our business.

Note 14 — Business Segment Information

We currently have four business segments: Well Intervention, Robotics, Subsea Construction and Production Facilities. Our Well Intervention segment includes our vessels and related equipment that are used to perform both heavy and light well intervention services primarily in the Gulf of Mexico and North Sea regions. Our well intervention vessels include the Q4000, the Helix 534, the Seawell, the Well Enhancer and the Skandi Constructor, which is chartered. We are currently constructing two additional well intervention vessels, the Q5000 and the Q7000. Our Robotics segment currently operates five chartered vessels and also includes ROVs, trenchers and ROVDrills designed to complement offshore construction and well intervention services. We have sold substantially all of the assets associated with our former Subsea Construction operations (Notes 1 and 2). The Production Facilities segment includes our consolidated investment in the HP I and Kommandor LLC as well as our equity investments in Deepwater Gateway and Independence Hub that are accounted for under the equity method. All material intercompany transactions between the segments have been eliminated. In February 2013, we sold ERT and as a result, we have presented the assets and liabilities included in the sale of ERT and the historical operating results of our former Oil and Gas segment as discontinued operations in the accompanying consolidated financial statements. See Note 3 for additional information regarding our discontinued operations.

We evaluate our performance based on operating income and income before income taxes of each segment. Segment assets are comprised of all assets attributable to each reportable segment. Corporate and other includes all assets not directly identifiable with our business segments, most notably the majority of our cash and cash equivalents. Certain financial data by reportable segment are summarized as follows (in thousands):

	Year Ended December 31,		
	2013	2012	2011

Revenues —			
Well Intervention	$452,452	$378,546	$340,952
Robotics	333,246	328,726	245,360
Subsea Construction	71,321	192,521	151,923
Production Facilities	88,149	80,091	75,460
Intercompany elimination	(68,607)	(133,775)	(111,695)
Total	$876,561	$846,109	$702,000

92

Table of Contents

	Year Ended December 31,		
	2013	2012	2011
Income (loss) from operations —			
Well Intervention	$131,840	$85,482	$80,030
Robotics	44,132	55,678	36,518
Subsea Construction (1)	33,685	(148,862)	(9,535)
Production Facilities	49,778	40,082	38,404
Corporate and other	(77,041)	(92,985)	(82,470)
Intercompany elimination	(3,360)	(7,878)	93
Total	$179,034	$(68,483)	$63,040
Net interest expense and other —			
Well Intervention	$(217)	$2,152	$(1,062)
Robotics	(210)	(1,203)	1,847
Subsea Construction	480	(247)	(20)
Production Facilities	380	365	442
Corporate and eliminations	37,978	64,882	72,475
Total	$38,411	$65,949	$73,682
Equity in earnings of equity investments	$2,965	$8,434	$22,215
Income (loss) before income taxes —			
Well Intervention	$132,057	$83,205	$72,642
Robotics	44,342	56,881	34,671
Subsea Construction	33,205	(148,615)	(9,515)
Production Facilities	52,363	48,276	58,064
Corporate and eliminations	(118,379)	(165,745)	(154,852)
Total	$143,588	$(125,998)	$1,010
Income tax provision (benefit) —			
Well Intervention	$26,718	$15,400	$21,154
Robotics	15,530	20,222	10,978
Subsea Construction	11,655	(51,329)	(2,897)
Production Facilities	17,233	15,784	19,233
Corporate and eliminations	(39,524)	(59,235)	(85,274)
Total	$31,612	$(59,158)	$(36,806)
Identifiable assets —			
Well Intervention	$1,245,229	$936,926	$682,449
Robotics	282,373	258,117	207,205
Subsea Construction	38,054	303,479	548,043
Production Facilities	495,829	504,828	536,026
Corporate and other	482,795	483,003	584,304
Discontinued operations	—	900,227	1,024,320
Total	$2,544,280	$3,386,580	$3,582,347
Capital expenditures —			
Well Intervention	$283,132	$274,451	$13,923
Robotics	39,655	44,500	27,045

Production Facilities	1,252	823	30,896
Corporate and other	387	3,265	28,290
Total	$324,426	$323,039	$100,154

Table of Contents

	Year Ended December 31, 2013	2012	2011
Depreciation and amortization —			
Well Intervention	$44,619	$37,736	$35,544
Robotics	22,263	19,933	16,426
Subsea Construction	8,651	19,773	21,321
Production Facilities	17,193	16,828	14,935
Corporate and eliminations	5,809	2,931	2,962
Total	$98,535	$97,201	$91,188

(1) Amount in 2013 includes the $1.1 million loss on the sale of the Caesar in June 2013 and the $15.6 million gain on the sale of the Express in July 2013. Amount in 2012 includes impairment charges of $157.8 million for the Caesar and $14.6 million for the Intrepid (Note 2).

Intercompany segment revenues during the years ended December 31, 2013, 2012 and 2011 are as follows (in thousands):

	Year Ended December 31, 2013	2012	2011
Well Intervention	$22,448	$36,781	$16,175
Robotics	41,169	46,465	45,251
Subsea Construction	317	4,472	4,212
Production Facilities	4,673	46,057	46,057
Total	$68,607	$133,775	$111,695

Intercompany segment profits (losses) (which only relate to intercompany capital projects) during the years ended December 31, 2013, 2012 and 2011 are as follows (in thousands):

	Year Ended December 31, 2013	2012	2011
Well Intervention	$(141)	$6,203	$(223)
Robotics	3,518	180	213
Subsea Construction	158	1,670	114
Production Facilities	(175)	(175)	(197)
Total	$3,360	$7,878	$(93)

Revenue by individually significant region during the years ended December 31, 2013, 2012 and 2011 is as follows (in thousands):

	Year Ended December 31, 2013	2012	2011
United States	$345,525	$281,308	$316,869
United Kingdom	403,816	345,074	275,499
Other	127,220	219,727	109,632
Total	$876,561	$846,109	$702,000

Table of Contents

We include the property and equipment, net in the geographic region in which it legally resides. The following table provides our property and equipment, net of accumulated depreciation, by individually significant region (in thousands):

	Year Ended December 31,		
	2013	2012	2011
United States	$1,195,824	$1,180,586	$1,163,320
United Kingdom	332,394	304,062	281,430
Other	76	1,227	14,919
Total	$1,528,294	$1,485,875	$1,459,669

Note 15 — Allowance Accounts

The following table sets forth the activity in our valuation accounts for each of the three years in the period ended December 31, 2013 (in thousands):

	Allowance for Uncollectible Accounts	Deferred Tax Asset Valuation Allowance
Balance at December 31, 2010	$ 4,460	$8,497
Additions (1)	61	5,813
Deductions	(521)	—
Balance at December 31, 2011	4,000	14,310
Additions (2)	1,257	2,081
Deductions	(105)	—
Balance at December 31, 2012	5,152	16,391
Additions (3)	2,236	6,469
Deductions (4)	(5,154)	—
Balance at December 31, 2013	$ 2,234	$22,860

(1) The increase in valuation allowance includes $4.9 million related to our former WOSEA operations and $0.9 million to our oil and gas operations in the United Kingdom.

(2) The increase in valuation allowance includes $2.0 million related to our former WOSEA operations and $0.1 million to our oil and gas operations in the United Kingdom. WOSEA has a full valuation allowance against its deferred tax asset balance.

(3) The increase in valuation allowance includes $6.5 million related to our former WOSEA operations. WOSEA has a full valuation allowance against its deferred tax asset balance.

(4) The decrease primarily reflects the reversal of a $4 million allowance against our trade receivables for work performed offshore India in 2007 as we collected the previously adjusted receivable balance pursuant to a settlement agreement (Note 13).

See Note 2 for a detailed discussion regarding our accounting policy on accounts receivable and allowance for uncollectible accounts and Note 8 for a detailed discussion of the valuation allowance related to our deferred tax assets.

Table of Contents

Note 16 — Derivative Instruments and Hedging Activities

Derivatives designated as hedging instruments are as follows (in thousands):

	As of December 31, 2013		As of December 31, 2012	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Asset Derivatives:				
Interest rate swaps	Other assets, net	$446	Other assets, net	$—
		$446		$—
Liability Derivatives:				
Foreign exchange contracts	Accrued liabilities	$1,905	Accrued liabilities	$—
Interest rate swaps	Accrued liabilities	746	Accrued liabilities	—
Foreign exchange contracts	Other non-current liabilities	13,166	Other non-current liabilities	—
		$15,817		$—

Derivatives that were not designated as hedging instruments are as follows (in thousands):

	As of December 31, 2013		As of December 31, 2012	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Asset Derivatives:				
Oil contracts	Other current assets	$—	Other current assets	$5,800
Foreign exchange contracts	Other current assets	69	Other current assets	146
		$69		$5,946
Liability Derivatives:				
Oil contracts	Accrued liabilities	$—	Accrued liabilities	$15,777
Interest rate swaps	Accrued liabilities	—	Accrued liabilities	489
Interest rate swaps	Other non-current liabilities	—	Other non-current liabilities	32
		$—		$16,298

As a result of the announcement in December 2012 of the sale of ERT, we de-designated all of our remaining oil and natural gas derivative contracts as hedging instruments. In addition, under the terms of our former credit agreement (Note 7), we were required to use a portion of the proceeds from the sales of ERT, the Caesar and the Express to make payments to reduce our indebtedness. Because of the probability that the former term loan debt would be totally repaid before the expiration of our then existing interest rate swaps, we also concluded that those swaps no longer qualified as cash flow hedges. At December 31, 2012, we recorded the mark-to-market adjustments for these derivatives to reflect the changes in their fair values and to recognize amounts previously recorded in accumulated other comprehensive income (loss) and related deferred taxes into earnings. The mark-to-market adjustments related to our commodity derivative contracts and interest rate swaps are reflected in “Loss on commodity derivative contracts” and “Other income (expense), net”, respectively, in the accompanying consolidated statements of operations. In February 2013, we settled all of our remaining commodity derivative contracts and then existing interest rate swap contracts for payments of approximately $22.5 million and $0.6 million, respectively.

In January 2013, we entered into foreign currency exchange contracts to hedge through September 2017 the foreign currency exposure associated with the Grand Canyon charter payments ($104.6 million) denominated in Norwegian kroner (NOK591.3 million). In February 2013, we entered into similar foreign currency exchange contracts for the

Grand Canyon II and Grand Canyon III charter payments ($100.4 million and $98.8 million, respectively) denominated in Norwegian kroner (NOK594.7 million and NOK595.0 million, respectively), through July 2019 and February 2020, respectively. These contracts currently qualify for hedge accounting treatment. All of our remaining foreign exchange contracts are not accounted for as hedge contracts and changes in their fair value are marked-to-market in earnings in each reporting period.

Table of Contents

In September 2013, we entered into interest rate swap contracts to fix the interest rate on $148.1 million of our Term Loan debt. These monthly contracts began in October 2013 and extend through October 2016. These contracts are accounted for under hedge accounting.

The following tables present the impact that derivative instruments designated as cash flow hedges had on our accumulated comprehensive income (loss) and our consolidated statements of operations for the years ended December 31, 2013, 2012 and 2011 (in thousands). The amount of any ineffectiveness associated with our cash flow hedges was immaterial for the years ended December 31, 2013, 2012 and 2011.

	Gain (Loss) Recognized in OCI on Derivatives, Net of Tax (Effective Portion) Year Ended December 31, 2013	2012	2011
Foreign exchange contracts	$(9,796)	$—	$—
Oil and natural gas commodity contracts	—	(12,860)	28,749
Interest rate swaps	(195)	(81)	1,294
	$(9,991)	$(12,941)	$30,043

	Location of Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)	Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion) Year Ended December 31, 2013	2012	2011
Oil and natural gas commodity contracts	Income from discontinued operations, net of tax	$—	$3,184	$(21,659)
Interest rate swaps	Net interest expense	(152)	(523)	(2,010)
Foreign exchange contracts	Cost of sales	(1,324)	—	—
		$(1,476)	$2,661	$(23,669)

The following table presents the impact that derivative instruments not designated as hedges had on our consolidated statement of operations for the years ended December 31, 2013, 2012 and 2011 (in thousands):

	Location of Gain (Loss) Recognized in Income on Derivatives	Gain (Loss) Recognized in Income on Derivatives Year Ended December 31, 2013	2012	2011
Oil and natural gas commodity contracts	Income from discontinued operations, net of tax	$—	$5,550	$—
Oil and natural gas commodity contracts	Loss on commodity derivative contracts	(14,113)	(10,507)	—
Interest rate swaps	Other expense, net	(86)	(567)	—
Foreign exchange contracts	Other expense, net	(630)	411	249
		$(14,829)	$(5,113)	$249

Note 17 — Quarterly Financial Information (Unaudited)

Offshore marine construction activities may fluctuate as a result of weather conditions and the timing of capital expenditures by oil and gas companies. Historically, a substantial portion of our services has been performed during the summer and fall months. As a result, historically a disproportionate portion of our revenues and net income is earned during such period. The following is a summary of consolidated quarterly financial information for 2013 and 2012 (in thousands, except per share amounts):

Table of Contents

2013	Quarter Ended March 31,	June 30,	September 30,	December 31,
Net revenues (1)	$ 197,429	$ 232,178	$ 220,117	$ 226,837
Gross profit (2)	52,567	67,497	69,457	71,164
Net income applicable to Helix:				
Income from continuing operations	$ 557	$ 27,240	$ 44,549	$ 36,503
Income from discontinued operations	1,058	(29)	44	—
Net income applicable to Helix	$ 1,615	$ 27,211	$ 44,593	$ 36,503
Basic earnings per common share:				
Income from continuing operations	$ 0.01	$ 0.26	$ 0.42	$ 0.35
Income from discontinued operations	0.01	—	—	—
Basic earnings per common share	$ 0.02	$ 0.26	$ 0.42	$ 0.35
Diluted earnings per common share:				
Income from continuing operations	$ 0.01	$ 0.26	$ 0.42	$ 0.35
Income from discontinued operations	0.01	—	—	—
Diluted earnings per common share	$ 0.02	$ 0.26	$ 0.42	$ 0.35

2012	Quarter Ended March 31,	June 30,	September 30,	December 31,
Net revenues (3)	$ 229,842	$ 197,461	$ 217,110	$ 201,696
Gross profit (loss) (4)	72,483	28,438	57,919	(108,925)
Net income (loss) applicable to Helix:				
Income (loss) from continuing operations	$ 16,874	$ 2,425	$ 10,362	$ (99,679)
Income (loss) from discontinued operations	48,853	42,216	4,503	(71,888)
Net income (loss) applicable to Helix (5)	$ 65,727	$ 44,641	$ 14,865	$ (171,567)
Basic earnings (loss) per common share:				
Income (loss) from continuing operations	$ 0.16	$ 0.02	$ 0.10	$ (0.95)
Income (loss) from discontinued operations	0.46	0.40	0.04	(0.69)
Basic earnings (loss) per common share	$ 0.62	$ 0.42	$ 0.14	$ (1.64)
Diluted earnings (loss) per common share:				
Income (loss) from continuing operations	$ 0.16	$ 0.02	$ 0.10	$ (0.95)
Income (loss) from discontinued operations	0.46	0.40	0.04	(0.69)
Diluted earnings (loss) per common share	$ 0.62	$ 0.42	$ 0.14	$ (1.64)

(1) Excludes revenues from discontinued operations of $48.8 million for the quarter ended March 31, 2013.

(2) Excludes gross profit from discontinued operations of $28.2 million for the quarter ended March 31, 2013.

(3) Excludes revenues from discontinued operations of $178.1 million, $149.9 million, $119.1 million and $110.1 million for the quarters ended March 31, June 30, September 30 and December 31, 2012.

(4) Excludes gross profit from discontinued operations of $89.2 million, $64.8 million, $27.8 million and $(102.6) million for the quarters ended March 31, June 30, September 30 and December 31, 2012. Includes impairment charges totaling $14.6 million in the second quarter of 2012, $4.6 million in the third quarter of 2012 and $158.0 million in the fourth quarter of 2012 (Note 2).

(5) Our net loss in the fourth quarter of 2012 includes a $138.6 million impairment charge associated with the sale of ERT (Note 3).

Table of Contents

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

(a) Evaluation of disclosure controls and procedures. Our management, with the participation of our principal executive officer and principal financial officer, evaluated the effectiveness of our disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) promulgated under the Securities Exchange Act of 1934, as amended (the "Exchange Act") as of the end of the fiscal year ended December 31, 2013. Based on this evaluation, the principal executive officer and the principal financial officer conclude that our disclosure controls and procedures were effective as of the end of the fiscal year ended December 31, 2013 to ensure that information that is required to be disclosed by us in the reports we file or submit under the Exchange Act is (i) identified, recorded, processed, summarized and reported, on a timely basis and (ii) accumulated and communicated to our management, as appropriate, to allow timely decisions regarding required disclosure.

(b) Changes in internal control over financial reporting. There have been no changes in our internal control over financial reporting, as defined in Rule 13a-15(f) of the Exchange Act, in the period covered by this report that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

(c) Changes in Internal Control. There was not any change in our internal control over financial reporting that occurred during the fourth quarter of fiscal 2013 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting and the Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting thereon are set forth in Part II, Item 8 of this report on Form 10-K on page 53 and page 54, respectively.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Except as set forth below, the information required by this Item is incorporated by reference to our definitive Proxy Statement to be filed pursuant to Regulation 14A under the Securities Exchange Act of 1934 in connection with our 2014 Annual Meeting of Shareholders to be held on May 1, 2014. See also "Executive Officers of the Registrant" appearing in Part I of this Report.

Code of Ethics

We have adopted a Code of Business Conduct and Ethics for all directors, officers and employees as well as a Code of Ethics for Chief Executive Officer and Senior Financial Officers specific to those officers. Copies of these documents are available at our Website www.helixesg.com under Corporate Governance. Interested parties may also request a free copy of these documents from:

Helix Energy Solutions Group, Inc.

ATTN: Corporate Secretary
3505 W. Sam Houston Parkway N., Suite 400
Houston, Texas 77043

Item 11. Executive Compensation

The information required by this Item is incorporated by reference to our definitive Proxy Statement to be filed pursuant to Regulation 14A under the Securities Exchange Act of 1934 in connection with our 2014 Annual Meeting of Shareholders to be held on May 1, 2014.

Table of Contents

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The information required by this Item is incorporated by reference to our definitive Proxy Statement to be filed pursuant to Regulation 14A under the Securities Exchange Act of 1934 in connection with our 2014 Annual Meeting of Shareholders to be held on May 1, 2014.

Item 13. Certain Relationships and Related Transactions, and Director Independence

The information required by this Item is incorporated by reference to our definitive Proxy Statement to be filed pursuant to Regulation 14A under the Securities Exchange Act of 1934 in connection with our 2014 Annual Meeting of Shareholders to be held on May 1, 2014.

Item 14. Principal Accounting Fees and Services

The information required by this Item is incorporated by reference to our definitive Proxy Statement to be filed pursuant to Regulation 14A under the Securities Exchange Act of 1934 in connection our 2014 Annual Meeting of Shareholders to be held on May 1, 2014.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(1) Financial Statements

The following financial statements included on pages 53 through 98 in this Annual Report are for the fiscal year ended December 31, 2013.

- Management's Report on Internal Control Over Financial Reporting
- Report of Independent Registered Public Accounting Firm
- Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting
- Consolidated Balance Sheets as of December 31, 2013 and 2012
- Consolidated Statements of Operations for the Years Ended December 31, 2013, 2012 and 2011
- Consolidated Statements of Comprehensive Income (Loss) for the Years Ended December 31, 2013, 2012 and 2011
- Consolidated Statements of Shareholders' Equity for the Years Ended December 31, 2013, 2012 and 2011
- Consolidated Statements of Cash Flows for the Years Ended December 31, 2013, 2012 and 2011
- Notes to Consolidated Financial Statements

All financial statement schedules are omitted because the information is not required or because the information required is in the financial statements or notes thereto.

(2) Exhibits

Pursuant to Item 601(b)(4)(iii), the Registrant agrees to forward to the commission, upon request, a copy of any instrument with respect to long-term debt not exceeding 10% of the total assets of the Registrant and its consolidated subsidiaries. Reference is made to Exhibit listing beginning on page 102 hereof.

Table of Contents

SIGNATURES

Pursuant to the requirements of section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

HELIX ENERGY SOLUTIONS GROUP, INC.

By: /s/ ANTHONY TRIPODO
Anthony Tripodo
Executive Vice President and
Chief Financial Officer

February 21, 2014

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ OWEN KRATZ	President, Chief Executive Officer and	February 21, 2014
Owen Kratz	Director (principal executive officer)	
/s/ ANTHONY TRIPODO	Executive Vice President and Chief	February 21, 2014
Anthony Tripodo	Financial Officer (principal financial officer)	
/s/ JAMES M. HALL	Chief Accounting Officer	February 21, 2014
James M. Hall	(principal accounting officer)	
/s/ JOHN V. LOVOI	Director	February 21, 2014
John V. Lovoi		
/s/ T. WILLIAM PORTER	Director	February 21, 2014
T. William Porter		
/s/ NANCY K. QUINN	Director	February 21, 2014
Nancy K. Quinn		
/s/ JAN A. RASK	Director	February 21, 2014
Jan A. Rask		
/s/ WILLIAM L. TRANSIER	Director	

William L. Transier		February 21, 2014
/s/ JAMES A. WATT James A. Watt	Director	February 21, 2014

101

Table of Contents

INDEX TO EXHIBITS

Exhibits	Description	Filed or Furnished Herewith or Incorporated by Reference from the Following Documents (Registration or File Number)
3.1	2005 Amended and Restated Articles of Incorporation, as amended, of registrant.	Exhibit 3.1 to the Current Report on Form 8-K filed on March 1, 2006 (000-22739)
3.2	Second Amended and Restated By-Laws of Helix, as amended.	Exhibit 3.1 to the Current Report on Form 8-K filed on September 28, 2006 (001-32936)
4.1	Credit Agreement dated July 3, 2006 by and among Helix Energy Solutions Group, Inc., and Bank of America, N.A., as administrative agent and as lender, together with the other lender parties thereto.	Exhibit 4.1 to the Current Report on Form 8-K filed on July 5, 2006 (001-32936)
4.2	Amendment No. 1 to Credit Agreement, dated as of November 29, 2007, by and among Helix, as borrower, Bank of America, N.A., as administrative agent, and the lenders named thereto.	Exhibit 10.3 to the Current Report on Form 8-K filed on December 21, 2007 (001-32936)
4.3	Amendment No. 2 to Credit Agreement, dated as of October 9, 2009, by and among Helix, as borrower, Bank of America, N.A., as administrative agent, and the lenders named thereto.	Exhibit 10.1 to the Current Report on Form 8-K filed on October 13, 2009 (001-32936)
4.4	Amendment No. 3 to Credit Agreement, dated as of February 19, 2010, by and among Helix, as borrower, Bank of America, N.A., as administrative agent, and the lenders named thereto.	Exhibit 10.1 to the Current Report on Form 8-K filed on February 24, 2010 (001-32936)
4.5	Amendment No. 4 to Credit Agreement, dated as of June 8, 2011, by and among Helix, as borrower, Bank of America, N.A., as administrative agent, swing line lender and L/C issuer, and the lenders named thereto.	Exhibit 10.1 to the Current Report on Form 8-K filed on June 9, 2011 (001-32936)
4.6	Amendment No. 5 to Credit Agreement dated November 11, 2011 by and among Helix Energy Solutions Group, Inc., as borrower, Bank of America, N.A., as administrative agent, and the lenders named thereto.	Exhibit 4.1 to the Current Report on Form 8-K filed on March 7, 2012 (001-32936)
4.7	Amendment No. 6 to Credit Agreement, dated as of February 21, 2012 by and among Helix, as borrower, Bank of America, N.A., as administrative agent, swing line lender and L/C issuer and the lenders named thereto.	Exhibit 4.6 to the 2011 Form 10-K filed on February 24, 2012 (001-32936)
4.8	Amendment No. 7 to Credit Agreement dated September 26, 2012 by and among Helix Energy Solutions Group, Inc., as borrower, Bank of America, N.A., as administrative agent, and the lenders named thereto.	Exhibit 10.1 to the Current Report on Form 8-K filed on October 1, 2012 (001-32936)
4.9	Amendment No. 8 to Credit Agreement dated February 19, 2013 by and among Helix Energy	Exhibit 4.9 to the 2012 Form 10-K filed on February 22, 2013

	Solutions Group, Inc., as borrower, Bank of America, N.A., as administrative agent, and the lenders named thereto.	(001-32936)
4.10	Form of Common Stock certificate.	Exhibit 4.7 to the Form 8-A filed on June 30, 2006 (001-32936)
4.11	Credit Agreement among Cal Dive I-Title XI, Inc., GOVCO Incorporated, Citibank N.A. and Citibank International LLC dated as of August 16, 2000.	Exhibit 4.4 to the 2001 Form 10-K filed on March 28, 2002 (000-22739)
4.12	Amendment No. 1 to Credit Agreement among Cal Dive I-Title XI, Inc., GOVCO Incorporated, Citibank N.A. and Citibank International LLC dated as of January 25, 2002.	Exhibit 4.9 to the 2002 Form 10-K/A filed on April 8, 2003 (000-22739)
4.13	Amendment No. 2 to Credit Agreement among Cal Dive I-Title XI, Inc., GOVCO Incorporated, Citibank N.A. and Citibank International LLC dated as of November 15, 2002.	Exhibit 4.4 to the Form S-3 filed on February 26, 2003 (333-103451)

Table of Contents

Exhibits	Description	Filed or Furnished Herewith or Incorporated by Reference from the Following Documents (Registration or File Number)
4.14	Amendment No. 3 Credit Agreement among Cal Dive I-Title XI, Inc., GOVCO Incorporated, Citibank N.A. and Citibank International LLC dated as of July 31, 2003.	Exhibit 4.12 to the 2004 Form 10-K filed on March 16, 2005 (000-22739)
4.15	Amendment No. 4 to Credit Agreement among Cal Dive I-Title XI, Inc., GOVCO Incorporated, Citibank N.A. and Citibank International LLC dated as of December 15, 2004.	Exhibit 4.13 to the 2004 Form 10-K filed on March 16, 2005 (000-22739)
4.16	Indenture relating to the 3.25% Convertible Senior Notes due 2025 dated as of March 30, 2005, between Cal Dive International, Inc. and JPMorgan Chase Bank, National Association, as Trustee.	Exhibit 4.1 to the Current Report on Form 8-K filed on April 4, 2005 (000-22739)
4.17	Form of 3.25% Convertible Senior Note due 2025.	Filed as Exhibit A to Exhibit 4.16 (000-22739)
4.18	Registration Rights Agreement dated as of March 30, 2005, between Cal Dive International, Inc. and Banc of America Securities LLC, as representative of the initial purchasers.	Exhibit 4.3 to the Current Report on Form 8-K filed on April 4, 2005 (000-22739)
4.19	Trust Indenture, dated as of August 16, 2000, between Cal Dive I-Title XI, Inc. and Wilmington Trust, as Indenture Trustee.	Exhibit 4.1 to the Current Report on Form 8-K filed on October 6, 2005 (000-22739)
4.20	Supplement No. 1 to Trust Indenture, dated as of January 25, 2002, between Cal Dive I-Title XI, Inc. and Wilmington Trust, as Indenture Trustee.	Exhibit 4.2 to the Current Report on Form 8-K filed on October 6, 2005 (000-22739)
4.21	Supplement No. 2 to Trust Indenture, dated as of November 15, 2002, between Cal Dive I-Title XI, Inc. and Wilmington Trust, as Indenture Trustee.	Exhibit 4.3 to the Current Report on Form 8-K filed on October 6, 2005 (000-22739)
4.22	Supplement No. 3 to Trust Indenture, dated as of December 14, 2004, between Cal Dive I-Title XI, Inc. and Wilmington Trust, as Indenture Trustee.	Exhibit 4.4 to the Current Report on Form 8-K filed on October 6, 2005 (000-22739)
4.23	Supplement No. 4 to Trust Indenture, dated September 30, 2005, between Cal Dive I-Title XI, Inc. and Wilmington Trust, as Indenture Trustee.	Exhibit 4.5 to the Current Report on Form 8-K filed on October 6, 2005 (000-22739)
4.24	Form of United States Government Guaranteed Ship Financing Bonds, Q4000 Series 4.93% Sinking Fund Bonds Due February 1, 2027.	Filed as Exhibit A to Exhibit 4.23 (000-22739)
4.25	Form of Third Amended and Restated Promissory Note to United States of America.	Exhibit 4.6 to the Current Report on Form 8-K filed on October 6, 2005 (000-22739)
4.26	Indenture, dated as of December 21, 2007, by and among Helix Energy Solutions Group, Inc., the Guarantors and Wells Fargo Bank, N.A.	Exhibit 4.1 to the Current Report on Form 8-K filed on December 21, 2007 (001-32936)
4.27	Indenture dated as of March 12, 2012 between Helix Energy Solutions Group, Inc. and The Bank of New York Mellon Trust Company, N.A., as Trustee.	Exhibit 4.1 to the Current Report on Form 8-K filed on March 12, 2012 (001-32936)

4.28	Credit Agreement dated June 19, 2013 by and among Helix Energy Solutions Group, Inc., as borrower, Bank of America, N.A., as administrative agent, swing line lender and letters of credit issuer, and other lender parties named thereto.	Exhibit 4.1 to the Current Report on Form 8-K filed on June 19, 2013 (001-32936)
10.1 *	1995 Long Term Incentive Plan, as amended.	Exhibit 10.3 to the Form S-1 filed on September 4, 1996 (333-11399)
10.2 *	Amendment to 1995 Long Term Incentive Plan of Helix Energy Solutions Group, Inc.	Exhibit 10.2 to the 2008 Form 10-K filed on March 2, 2009 (001-32936)
10.3 *	2009 Long-Term Incentive Cash Plan of Helix Energy Solutions Group, Inc.	Exhibit 10.1 to the Current Report on Form 8-K filed on January 6, 2009 (001-32936)

Table of Contents

Exhibits	Description	Filed or Furnished Herewith or Incorporated by Reference from the Following Documents (Registration or File Number)
10.4 *	Form of Award Letter related to the 2009 Long-Term Incentive Cash Plan.	Exhibit 10.2 to the Current Report on Form 8-K filed on January 6, 2009 (001-32936)
10.5 *	Employment Agreement between Owen Kratz and the Company dated February 28, 1999.	Exhibit 10.5 to the 1998 Form 10-K filed on March 31, 1999 (000-22739)
10.6 *	Employment Agreement between Owen Kratz and the Company dated November 17, 2008.	Exhibit 10.1 to the Current Report on Form 8-K filed on November 19, 2008 (001-32936)
10.7 *	Helix 2005 Long Term Incentive Plan, including the Form of Restricted Stock Award Agreement.	Exhibit 10.1 to the Current Report on Form 8-K filed on May 12, 2005 (000-22739)
10.8 *	Amendment to 2005 Long Term Incentive Plan of Helix Energy Solutions Group, Inc.	Exhibit 10.10 to the 2008 Form 10-K filed on March 2, 2009 (001-32936)
10.9 *	Employment Agreement between Alisa B. Johnson and the Company dated November 17, 2008.	Exhibit 10.3 to the Current Report on Form 8-K filed on November 19, 2008 (001-32936)
10.10	Registration Rights Agreement dated as of December 21, 2007 by and among Helix Energy Solutions Group, Inc., the Guarantors named therein and Banc of America Securities LLC, as representative of the Initial Purchasers.	Exhibit 10.1 to the Current Report on Form 8-K filed on December 21, 2007 (001-32936)
10.11	Purchase Agreement dated as of December 18, 2007 by and among Helix Energy Solutions Group, Inc., the Guarantors named therein and Banc of America Securities LLC, and the other Initial Purchasers named therein.	Exhibit 10.2 to the Current Report on Form 8-K filed on December 21, 2007 (001-32936)
10.12	Employment Agreement between Anthony Tripodo and the Company dated June 25, 2008.	Exhibit 10.2 to the Current Report on Form 8-K filed on June 30, 2008 (001-32936)
10.13 *	First Amendment to Employment Agreement between Anthony Tripodo and the Company dated November 17, 2008.	Exhibit 10.5 to the Current Report on Form 8-K filed on November 19, 2008 (001-32936)
10.14 *	Employment Agreement between Lloyd A. Hajdik and the Company dated November 17, 2008.	Exhibit 10.4 to the Current Report on Form 8-K filed on November 19, 2008 (001-32936)
10.15 *	Employment Agreement by and between Helix Energy Solutions Group, Inc. and Johnny Edwards dated May 11, 2011.	Exhibit 10.1 to the Current Report on Form 8-K filed on May 13, 2011 (001-32936)
10.16 *	Employment Agreement by and between Helix Energy Solutions Group, Inc. and Clifford Chamblee dated May 11, 2011.	Exhibit 10.3 to the Quarterly Report on Form 10-Q filed on July 27, 2011 (001-32936)
10.17 *	Form of Cash Award Agreement.	Exhibit 10.1 to the Current Report on Form 8-K filed on December 15, 2011 (001-32936)
10.18 *	Form of Performance Units Award Agreement.	

		Exhibit 10.2 to the Current Report on Form 8-K filed on December 15, 2011 (001-32936)
10.19 *	Form of Restricted Stock Award Agreement.	Exhibit 10.3 to the Current Report on Form 8-K filed on December 15, 2011 (001-32936)
10.20	Construction contract dated as of March 12, 2012 between Helix Energy Solution Group, Inc. and Jurong Shipyard Pte Ltd.	Exhibit 10.1 to the Current Report on Form 8-K filed on March 16, 2012 (001-32936)

Table of Contents

Exhibits	Description	Filed or Furnished Herewith or Incorporated by Reference from the Following Documents (Registration or File Number)
10.21	The MODU Sale Agreement between Helix Energy Solutions Group, Inc. and Transocean Discoverer 534 LLC dated July 23, 2012.	Exhibit 10.2 to the Quarterly Report on Form 10-Q filed on July 25, 2012 (001-32936)
10.22 *	Amended and Restated 2005 Long-Term Incentive Plan of Helix Energy Solutions Group, Inc. dated May 9, 2012.	Exhibit 10.3 to the Quarterly Report on Form 10-Q filed on July 25, 2012 (001-32936)
10.23 *	Employee Stock Purchase Plan of Helix Energy Solutions Group, Inc. dated May 9, 2012.	Exhibit 10.4 to the Quarterly Report on Form 10-Q filed on July 25, 2012 (001-32936)
10.24	The Pipelay Asset Sale Agreement between Helix Energy Solutions Group, Inc. and Coastal Trade Limited dated October 15, 2012.	Exhibit 10.1 to the Current Report on Form 8-K filed on October 17, 2012 (001-32936)
10.25	Equity Purchase Agreement dated December 12, 2012, between Helix Energy Solutions Group, Inc. and Talos Production LLC.	Exhibit 10.1 to the Current Report on Form 8-K filed on December 13, 2012 (001-32936)
10.26	Third Correction Assignment of Overriding Royalty Interest dated December 12, 2012, by and between Energy Resource Technology GOM, Inc. and OKCD Investments, Ltd.	Exhibit 10.2 to the Current Report on Form 8-K filed on December 13, 2012 (001-32936)
10.27	Form of Indemnification Agreement, by and among Talos Production LLC, Energy Resource Technology GOM, LLC, CKB Petroleum, LLC, and Helix Energy Solutions Group, Inc.	Exhibit 10.3 to the Current Report on Form 8-K filed on December 13, 2012 (001-32936)
10.28 *	Non-Competition and Non-Solicitation Agreement dated December 12, 2012, by and among Energy Resource Technology GOM, Inc., CKB Petroleum, Inc., and Johnny Edwards.	Exhibit 10.4 to the Current Report on Form 8-K filed on December 13, 2012 (001-32936)
10.29 *	First Amendment to Employment Agreement dated December 12, 2012, by and between Helix Energy Solutions Group, Inc. and Johnny Edwards.	Exhibit 10.5 to the Current Report on Form 8-K filed on December 13, 2012 (001-32936)
10.30	Amendment No. 1 to Equity Purchase Agreement dated January 27, 2013, between Helix Energy Solutions Group, Inc. and Talos Production LLC.	Exhibit 10.1 to the Current Report on Form 8-K filed on January 28, 2013 (001-32936)
10.31	Amendment No. 2 to Equity Purchase Agreement dated February 6, 2013, between Helix Energy Solutions Group, Inc. and Talos Production LLC.	Exhibit 10.1 to the Current Report on Form 8-K filed on February 12, 2013 (001-32936)
10.32 *	Separation and Release Agreement dated April 24, 2013 between Helix Energy Solutions Group, Inc. and Lloyd A. Hajdik.	Exhibit 10.3 to the Quarterly Report on Form 10-Q filed on April 24, 2013 (001-32936)
10.33	Construction Contract dated as of September 11, 2013 between Helix Q7000 Vessel Holdings S.à r.l. and Jurong Shipyard Pte Ltd.	Exhibit 10.1 to the Current Report on Form 8-K filed on September 13, 2013 (001-32936)
14.1	Code of Ethics for Chief Executive Officer and Senior Financial Officers.	Exhibit 14.1 to the Registrant's Current Report on Form 8-K filed on December 8, 2009 (001-32936)

21.1	List of Subsidiaries of the Company.	Filed herewith
23.1	Consent of Ernst & Young LLP.	Filed herewith
23.2	Consent of Deloitte & Touche LLP. (Deepwater Gateway L.L.C.).	Filed herewith
23.3	Consent of Deloitte & Touche LLP. (Independence Hub LLC).	Filed herewith
31.1	Certification Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934 by Owen Kratz, Chief Executive Officer.	Filed herewith

Table of Contents

Exhibits	Description	Filed or Furnished Herewith or Incorporated by Reference from the Following Documents (Registration or File Number)
31.2	Certification Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934 by Anthony Tripodo, Chief Financial Officer.	Filed herewith
32.1	Certification of Helix's Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes — Oxley Act of 2002.	Furnished herewith
101.INS	XBRL Instance Document.	Furnished herewith
101.SCH	XBRL Schema Document.	Furnished herewith
101.CAL	XBRL Calculation Linkbase Document.	Furnished herewith
101.PRE	XBRL Presentation Linkbase Document.	Furnished herewith
101.DEF	XBRL Definition Linkbase Document.	Furnished herewith
101.LAB	XBRL Label Linkbase Document.	Furnished herewith

* Management contracts or compensatory plans or arrangements